Final
Determination of Compliance

Valero Cogeneration Project
102 Mw Power Plant
Phase I and Phase II

Bay Area Air Quality Management District

Applications Number 2488 and 2695

October 4, 2001

Douglas W. Hall

Supervising Air Quality Engineer

Contents

PHASE I and Phase II

I. Introduction

This is the Final Determination of Compliance (FDOC) for the Valero Cogeneration Project at the existing Valero Energy Corporation (Valero) refinery in Benicia, California [a 102-MW, refinery fuel gas/natural-gas fired, Cogeneration power plant]. The site is located in Block 25, Township 3 North, Range 3 West of the Benicia Quadrangle, Solano County. The project site was selected because of its proximity to the electrical switch house and the refinery processing area.

The proposed plant will consist of two 51 megawatt (MW) combined-cycle gas turbines with chillers, Heat Recovery Steam Generators (HRSG's), Selective Catalytic Reduction (SCR) and oxidation catalyst systems for emissions control, a small package cooling tower, and associated instrumentation, piping and wiring. The HRSG's will produce superheated steam at 600 psi for use in the refinery's processes, replacing the steam generated by three existing package boilers (S-38, S-39, S-41). These boilers will be shut down.

Valero has submitted Applications number 2488 (Phase I) and 2695 (Phase II) for an Authority to Construct and Permit to Operate for this 102-megawatt power plant. Each application is for permits to operate a gas turbine and heat recovery steam generator (HRSG) representing one half of the proposed project. In order to ensure that the entire impact of the proposed project is addressed in advance, Phase I and Phase II have been evaluated together. This FDOC covers both Phase I and Phase II.

The gas turbine/HRSG systems will be fired on refinery fuel gas and/or natural gas.

A. Background

Pursuant to BAAQMD Regulation 2, Rule 3, Section 403, this document serves as the Final Determination of Compliance (FDOC) for the Valero Cogeneration Project. It will also serve as the evaluation report for the BAAQMD Authority to Construct applications #2488 and #2695. The FDOC describes how the proposed facility will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology (BACT) and emission offset requirements of the District New Source Review (NSR) regulation. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included. This document includes a health risk assessment that demonstrates that the impact of project emissions on public health meets District Risk Management Guidelines. An air quality impact analysis for particulates (PM10), sulfur dioxide (SO2), nitrogen oxide (NOx) and carbon monoxide (CO), following PSD guidelines, was performed by Valero as required by the California Energy Commission (CEC). Although the project net emissions do not require prevention of significant deterioration (PSD) analysis, the impact analysis has been reviewed by the District's Planning Division. The impact analysis demonstrates that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

In accordance with BAAQMD Regulation 2, Rule 3, Section 404, the PDOC was subject to the public notice and public inspection requirements of District Regulation 2, Rule 2, Sections 406 and 407. The PDOC was made available for public comment on August 20, 2001. Comments were received from California Unions for Reliable Energy (CURE), Environmental Protection Agency (EPA), City of Benicia, two members of the public and the applicant. The public comment period closed on September 20, 2001.

B. Project Description

1. Process Equipment

The applicant is proposing two combustion turbine power generation units with a maximum electrical output of 51 MW each. The first unit will produce electricity for the Valero refinery which will virtually eliminate the need for imported utility power. The second unit will produce electricity that can be exported into the grid for use by other businesses and households in Northern California. The equipment to be permitted by the first and second unit is as follows:

<u>Phase I</u>

S-1030 Combustion Turbine Generator: General Electric, Model LM 6000, 500 MM Btu/hr maximum rated capacity, Refinery Fuel Gas and/or Natural Gas Fired; water injected low NOx Burners; Abated by A-60 Selective Catalytic Reduction (SCR) System and A-61 CO Oxidizing Catalyst System

S-1031 Heat Recovery Steam Generator (HRSG): Duct Burner Supplemental Firing System, 310 MM Btu/hr maximum rated capacity; abated by A-60 Selective Catalytic Reduction (SCR) System and A-61 CO Oxidizing Catalyst System

<u>Phase II</u>

S-1032 Combustion Turbine Generator: General Electric, Model LM 6000, 500 MM Btu/hr maximum rated capacity, Refinery Fuel Gas and/or Natural Gas Fired; water injected low NOx Burners; Abated by A-62 Selective Catalytic Reduction (SCR) System and A-63 CO Oxidizing Catalyst System

S-1033 Heat Recovery Steam Generator (HRSG): Duct Burner Supplemental Firing System, 310 MM Btu/hr maximum rated capacity; abated by A-62 Selective Catalytic Reduction (SCR) System and A-63 CO Oxidizing Catalyst System

EXEMPTION

Exempt Wet Cooling Tower: 540,000 cfm air flow rate, 5600 gpm water circulation rate for both phases (Exempt per Regulation 2-1-128.4: Water cooler tower not used for evaporative cooling of process water)

This Wet Cooling Tower is exempt from the District permitting requirements per Regulation 2-1-128.4 because it is not used for the evaporative cooling of process water. It will emit less than 5 tons per year of particulates and does not trigger a toxic risk screen. Valero intends to circulate fresh water obtained from the City of Benicia through the exempt wet cooling tower. Estimated project emissions from this source is 0.66 ton per year. PM10 emissions would be much higher if recycled water were used instead of fresh water. The PM10 emissions, as represented in the PDOC on recycled water, would approach 4 tons per year. If recycled water is used, Valero will offset this PM10 increase by using available contemporaneous emission reduction credits and/or by inducing operating constraints. The risk assessment was based on the use of recycled water for this project.

2. Air Pollution Control Strategies, BACT, and Equipment

The proposed power plant includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2) for emissions of nitrogen oxides (NOx), carbon monoxide (CO), precursor organic compounds (POCs), sulfur dioxide (SO2), and particulate matter of less than 10 microns in diameter (PM10).

a. Selective Catalytic Reduction with Ammonia Injection for the Control of NOx

The gas turbines and HRSG duct burners each trigger BACT for NOx emissions. The gas turbines will be equipped with water injected combustors, which are designed to minimize NOx emissions. The HRSGs will be equipped with low-NOx duct burners, which are designed to minimize NOx emissions. In addition, the combined NOx emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection. When firing refinery fuel gas or natural gas, the gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level NOx emission limit of 2.5 ppmvd @ 15 % O2. The averaging period shall be one hour when firing natural gas and three hours when firing refinery fuel gas.

b. Oxidation Catalyst to Minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The HRSGs will be equipped with a CO catalyst designed to catalytically oxidize the CO and POC produced from firing natural gas and/or refinery gas in the gas turbine and duct burner. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level CO emission limit of 6 ppmvd @ 15 % O2.

c. Oxidation Catalyst to Minimize POC Emissions
The Gas Turbines and HRSGs each trigger BACT for POC emissions. The HRSGs will be equipped with a CO catalyst to minimize CO and POC emissions. The gas turbine and HRSG duct burner combined exhaust are expected to achieve a BACT-level POC emission limit of 2.0 ppmvd @ 15 % O2 with natural gas fuel and/or refinery fuel gas.

d. Amine Scrubber to Minimize SO2 and PM10 Emissions
The gas turbine and HRSG duct burners each trigger BACT for SO2 and PM10. The amount of SO2 emissions in the exhaust stream is a function of the sulfur levels in the combusted fuel gas, which is a blend of refinery gas and natural gas. The limit on the total reduced sulfur (TRS) level presently in the refinery gas is 51 ppm. This level of TRS control is achieved through the use of an amine scrubber. BACT for sources combusting refinery gas has been determined to be 35 ppm, averaged over any consecutive 365 day period, or equivalent control. PM10 emissions are minimized through the use of good combustion practices.

II. Facility Emissions

A. Maximum Hourly Mass Rate for Each Pollutant

1. NOx Maximum Hourly Mass Emissions Rate

The NOx emission limit for this proposed power plant is 2.5 ppmv. The NOx emissions from the turbines and HRSGs will be limited by permit condition to 2.5 ppmv, dry @ 15% O2, averaged over one hour for natural gas and three hours for refinery fuel gas.

Gas Turbine NOx Emissions Factor (S-1030 and S-1032)
This concentration is converted to a mass emission factor, for gas turbine firing only, with no duct burner firing as follows:

(2.5 ppmvd)(20.95-0)/(20.95 - 15) = 8.80 ppmv NOx, dry @ 0% O2

(8.8/1,000,000)(1 lbmol/385.3 dscf)(46.01 lb NO2/lbmol)(8600 dscf/MM Btu)
= 0.009 lb NO2/MM Btu

Duct Burner NOx Emissions Factor (S-1031 and S-1033)
This concentration is converted to a mass emission factor for the firing of the duct burners only as follows:

The additional NOx emissions from firing the duct burner are based on manufacturer emission factors (0.09 lb/MM Btu per J Zink) and at least 90% control of NOx emissions by the SCR. The emissions are calculated as follows:

Emission factor = 0.009 lb NO2/MMBtu

NOx Maximum Hourly Mass Emissions Rate

The NOx mass emission rate based on maximum hourly firing of the proposed power plant (S-1030, S-1031, S-1032, S-1033) is calculated as follows:

Given: 2 turbines (S-1030 and S-1032) @ 500 MM Btu/hr each = 1000 MM Btu/hr
2 HRSG (S-1031 and S-1033) @ 310 MM Btu/hr each = 620 MM Btu/hr
Total= 1620 MM Btu/hr

1620 MM Btu/hr x 0.009 lb NOx/MM Btu = **14.58 lb NOx/hr**
Total emission rate for each train = 14.58 lb NOx/hr / 2 = **7.29 lb NOx/hr**

2. CO Maximum Hourly Mass Emissions Rate

The CO emission limit for the proposed power plant is 6.0 ppmv, dry, @ 15% O2. This concentration is converted to a mass emission factor as follows:

(6.0 ppmvd)(20.95-0)/(20.95 - 15) = 21.126 ppmv CO, dry @ 0% O2

(21.126/1,000,000)(1 lbmol/385.3 dscf)(28 lb CO/lbmol)(8600 dscf/MMBtu)
= **0.0132 lb CO/MMBtu**

The CO mass emission rate based on the maximum hourly firing rate of the two gas turbines and HRSGs (S-1030, S-1031, S-1032, S-1033) is calculated as follows:

(0.0132 lb CO/MMBtu)(1620 MMBtu/hr) = **21.384 lb CO/hr**
Total emission rate for each train = 21.384 lb CO/hr / 2 = **10.692 lb CO/hr**

3. POC Maximum Hourly Mass Emissions Rate

The POC emission limit for the proposed power plant is 2.0 ppmv, dry @ 15% O2. The volume concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95-0)/(20.95 - 15) = 7.04 ppmv POC as CH4, dry @ 0% O2

(7.04/1,000,000)(1 lbmol/385.3 dscf)(16 lb CH4/lbmol)(8600 dscf/MMBtu)
= **0.002515 lb POC as CH4/MM Btu**

The POC mass emission rate, with POC expressed as CH4, based on the maximum hourly firing rate of the two turbines and HRSGs (S-1030, S-1031, S-1032 and S-1033) is calculated as:

(0.002515 lb POC/MMBtu)(1620 MMBtu/hr) = **4.074 lb POC/hr**
Total emission rate for each train = 4.074 lb POC/hr / 2 =**2.037 lb POC/hr**

4. SO2 Maximum Hourly Mass Emissions Rate

The SO2 emission from the proposed power plant consisting of two gas turbines and two HRSGs (S-1030, S-1031, S-1032, S-1033) will be limited by permit condition based on the following fuel concentration limits:

24-hour Average: 100 ppm Total Reduced Sulfur (TRS)

Emission Factor for Refinery Fuel Gas

RFG (MM scf/hr	=	MM Btu/hr / Btu/scf
	=	1620 MM Btu/hr / 1251 Btu/scf (HHV)
	=	1.295 MM scf/hr
SO2 (lb mole/hr)	=	$\frac{100 \text{ x } 1.295 \text{ scf/hr x } 10^6}{10^6 \text{ x } 385.3 \text{ scf/lb mole}}$
	=	0.336 lb mole/hr
SO2 (lb/hr)	=	0.336 lb mole/hr x 64 lb SO2/lb mole
	=	21.5 lb/hr

Rolling 24 hour Average @ 100 ppm TRS = **21.5 lb SO2/hr**

5. PM10 Maximum Hourly Mass Emissions Rate

The PM10 emission from both the gas turbines and the HRSGs (S-1030, S-1031, S-1032, S-1033) will be limited by permit condition to no more than 9.3 pounds per hour. The applicant has proposed these levels for purposes of a maximum hourly limit, and has plausibly supported the request with source test data. Each power train will be limited to no more than 4.65 pounds per hour of PM10 emissions.

As discussed below, the proposed PM10 levels are less than, but similar to, levels achieved by similar equipment. The PM10 limitation for the Cogeneration Project will be adjusted to reflect measured levels actually achieved. If these levels are higher than the levels proposed by the applicant, operation of the Cogeneration equipment will be limited to the emissions assumed by this evaluation.

The California Air Resources Board (CARB) has published a report containing PM10 source test results for combined cycle, cogeneration gas turbines. The report can be found in the "Guidance for Power Plant Siting and BACT", July 1999. The relevant page has been excerpted from that document and is shown in **Appendix A**. Two separate source tests were conducted on October 1995 and November 1996 on a General Electric LM 6000 gas turbine with auxiliary-fired HRSG firing natural gas producing 42 MW. The source test results were 1.01 lb/hr and 2.08 lb/hr, respectively. Extrapolating the higher emissions rate of 2.08 lb/hr (conservative) to 51 MW yields 2.53 lb/hr PM10 for one turbine train, or 5.06 lb/hr for both. Assuming a 35% higher PM10 because of the higher sulfur in the refinery fuel gas (35 ppm) over natural gas (3-6 ppm) yields 3.2 lb/hr PM10 for one turbine train, or 6.4 for both. For purposes of PM10 modeling, Valero used 4.65 lb/hr PM10 for one turbine train, or 9.3 lb/hr for both. For this Cogeneration project, the maximum hourly rate will be set at the values used for modeling.

6. Ammonia Emissions

The ammonia (NH_3) mass emission rate from the turbines and HRSGs (S-1030, S-1031, S-1032, S-1033) will be limited by permit condition to 10.0 ppmv, dry @ 15% O_2, based upon vendor guarantees. The maximum NH_3 mass emission rate based on the maximum hourly firing rate of the turbine and HRSG is calculated as follows:

(10.0 ppmvd)(20.95-0)/(20.95 - 15) = 35.21 ppmv NH_3, dry @ 0% O_2

(35.21/1,000,000)(1 lbmol/385.3 dscf)(17 lb NH_3/lbmol)(8600 dscf/MMBtu)
= **0.013 lb NH_3/MM Btu**

(0.013 lb NH_3/MMBtu)(1620 MMBtu/hr) = **21.06 lb NH_3/hr**
Total emission rate for each power train = 21.06 lb NH_3/hr / 2 = **10.53 lb NH_3/hr**

B. Maximum Daily Mass Rate for Each Pollutant

1. Maximum Hourly Startup/Shut down Emissions, lb/hr

The start-up/shutdown (non-baseload) data is based on information previously provided by the manufacturer for a General Electric LM 6000, 51 MW to the CEC [Application 12809, United Golden Gate Power Plant (Data Request Response #2, Item #19, dated 12/15/00)]. A start-up is anticipated to take an average of ten minutes for the gas turbine. Hourly and start-up emission estimates were provided to the applicant by S&S Energy Products, a General Electric Power Systems Business. District and CEC staff concurred with the values submitted by the manufacturer. These values will be used for this project because Valero will install an identical gas turbine.

General Electric Start-up/Stop Emissions, lb-turbine/hour-start/stop

Source	NOx	POC	CO	PM10
S-1030	7.7	0.68	7.7	3.14
S-1031[1]	4.8	0.42	4.8	1.95
S-1032	7.7	0.68	7.7	3.14
S-1033[1]	4.8	0.42	4.8	1.95
Total	25.0	2.2	25.0	10.18
Each Phase	12.5	1.1	12.5	5.09

[1]Assuming emissions rate for duct burners (per month) will be same as turbines

2. Maximum Daily Mass Rate including Startup and Shutdown Emissions

For NOx and PM10, the worst case daily emission scenario is one hour of Startup and shutdown emissions and 23 hours at full capacity. For all other pollutants, worst case daily emissions are 24 hours at full capacity.

Proposed Power Plant (S-1030, S-1031, S-1032, S-1033)
Maximum Operating Hourly Mass Emissions from Part II, A (1 through 5)
Maximum Startup and Shut down emissions from the table in Part II, B.1.
Startup and shutdown emissions limited to 1 hour. Start up and shutdown
Emissions are included when the hourly rate exceeded the hourly baseload rate.

NOx = (25 lb/hr-start/stop) (1 start) + (14.58 lb/hr-baseload) (23 hr)
= 25 + 335.34 = **360.34 lb/day NOx**

CO = (21.384 lb/hr-baseload)(24 hr/day)
= **513.216 lb/day CO**

POC = (4.074 lb/hr-baseload)(24 hr/day)
= **97.776 lb/day POC**

PM10 = (10.18 lb/hr-start/stop) (1 start) + (9.3 lb/hr-baseload)(23 hr)
= 10.18 + 213.9 = 224.08 **lb/highest day PM10**

SO2 @ 100ppm TRS (24 hour average) Condition limit
SO2 = (21.5 lb/hr-baseload) (24 hour/day)
= **516 lb/highest day SO2**

Emission Factor for Refinery Fuel Gas

RFG (MM scf/hr	=	MM Btu/hr / Btu/scf
	=	1620 MM Btu/hr / 1251 Btu/scf (HHV)
	=	1.295 MM scf/hr
SO2 (lb mole/hr)	=	$\frac{100 \times 1.295 \text{ scf/hr} \times 10^6}{10^6 \times 385.3 \text{ scf/lb mole}}$
	=	0.336 lb mole/hr
SO2 (lb/hr)	=	0.336 lb mole/hr x 64 lb SO2/lb mole
	=	21.5 lb/hr

C. Annual Emissions for Each Pollutant

Annual Emissions, tons/year:

Given: Maximum Hourly Firing Rate
2 turbines (S-1030 and S-1032) @ 500 MM Btu/hr each = 1000 MM Btu/hr
2 HRSG (S-1031 and S-1033) @ 310 MM Btu/hr each = 620 MM Btu/hr
Total = 1620 MM Btu/hr
For each power train = 1620/2 = 810 MM Btu/hr

Given: Anticipated Hourly Firing Rate (Annual Average)
2 turbines (S-1030 and S-1032) @ 465 MM Btu/hr each = 930 MM Btu/hr
2 HRSG (S-1031 and S-1033) @ 260 MM Btu/hr each = 520 MM Btu/hr
Total = 1450 MM Btu/hr
For each power train = 1450/2 = **725 MM Btu/hr**

Based on year round operation at a nominal firing rate of 1450 MMBtu/hr.
365 days x 24 hrs/day = 8760 hrs/year
Use 8 hours per year for startup/shutdown (baseload operation).

NOx emissions calculation:
[(25 lb/hr x 8 hr/yr) + (0.009 lb NOx/MM Btu x 1450 MM Btu/hr x (8760 hr/yr - 8 hr/yr startup and shutdown))] [ton/2000 lb] = (200 + 114,213.6)/2000 = **57.207 tons/yr NOx**
For each power train = 57.207 / 2 = **28.603 tons/yr NOx**

CO emissions calculation:
[(25 lb/hr x 8 hr/yr) + (0.0132 lb CO/MM Btu x 1450 MM Btu/hr x (8760 hr/yr - 8 hr/yr startup and shutdown))] [ton/2000 lb] = (200 + 167,513.3)/2000 = **83.857 tons/yr CO**
For each power train = 139.694 / 2 = **41.9285 tons/yr CO**

POC emissions calculation:
[(2.2 lb/hr x 8 hr/yr) + (0.002515 lb POC/MM Btu x 1450 MM Btu/hr x (8760 hr/yr - 8 hr/yr startup and shutdown))] [ton/2000 lb]
= (17.6 + 31,916.4)/2000 = **15.967 tons/yr POC**
For each power train = 15.967 / 2 = **7.983 tons/yr POC**

SO2 emissions calculation:
35 ppm TRS
[(0.0047[1] lb SO2/MM Btu x 1450 MM Btu/hr x (8752 hr/yr + 8 hr/yr startup and shutdown))] [ton/2000 lb]
= 59,699/2000 = **30.0 tons/yr SO2**
For each power train = **15.0 tons/yr SO2**

[1]Emission Factor for Refinery Fuel Gas

RFG (MM scf/hr	=	MM Btu/hr / Btu/scf
	=	1620 MM Btu/hr / 1251 Btu/scf (HHV)
	=	1.295 MM scf/hr
SO2 (lb mole/hr)	=	$\frac{35 \text{ x } 1.295 \text{ scf/hr x } 10^6}{10^6 \text{ x } 385.3 \text{ scf/lb mole}}$
	=	0.118 lb mole/hr
SO2 (lb/hr)	=	0.118 lb mole/hr x 64 lb SO2/lb mole
	=	7.552 lb SO2/hr
SO2 (lb SO2/MM Btu)	=	(7.552 lb SO2/hr) / (1620 MM Btu/hr)
	=	**0.0047 lb SO2/MM Btu**

PM10 emissions calculation:

Valero has proposed a level of 1.55 lb/hr for one turbine train or 3.1 lb/hr for both on an annual average based on the average test results described earlier.

[(10.18 lb/hr x 8 hr/yr) + (3.1 lb/hr x (8760 - 8))] [1 ton/2000 lb]
= (81.44 + 27131.2)/2000 = **13.606 tons/yr**
For each power train = 13.606 / 2 = **6.803 tons/yr PM10**

Note that the worst-case hourly PM10 emissions, as presented in the Emissions Section II-A-5, are expected to be as high as 9.3 lbs/hour. Actual PM10 emissions will be determined by source test. If the actual emissions are higher than assumed, Valero will be required to restrict operations (reduce firing or lower fuel sulfur) to remain below PSD threshold of 15 tons/year for this project.

Valero has already conducted a PSD analysis, assuming particulate emissions of 9.3 lbs/hr. The modeling results are shown in Appendix F, and show that the Cogeneration project will not interfere with the attainment of any federal air quality standard.

Therefore, if the Cogeneration project particulate emissions rate exceeds the assumed levels, the project's total emissions will still be restricted to the amount of offsets that have been provided with this application. This will ensure that PSD threshold for PM10 is not exceeded.

Source tests, initial and quarterly for at least the first year, will be utilized to monitor compliance and also to develop an emission factor reflecting fuel sulfur content (TRS) and firing rate impacts on PM10 emissions. The developed factor will be utilized to demonstrate compliance with the emission limits.

Fugitive POC Emissions

Valero intends to install 600 valves, 4 compressors and 1800 flanges (connectors) to be used in this Power Plant Project. The POC emissions from the fugitive equipment were estimated at 0.945 ton/year. (See Table I).

Table I

Phase I – Fugitive POC emissions, tons/yr

Component	Count	1b/comp/day	lb/day	TPY
Valves	400	0.00179	0.716	0.131
Flanges	1200	0.00166	1.992	0.363
Compressors	2	0.28	0.56	0.102
Total			3.268	0.596

Phase II – Fugitive POC emissions, tons/yr

Component	Count	1b/comp/day	lb/day	TPY
Valves	200	0.00179	0.358	0.065
Flanges	600	0.00166	0.996	0.182
Compressors	2	0.28	0.56	0.102
Total			1.914	0.349

Phase I and Phase II– Fugitive POC emissions, tons/yr

Component	Count	1b/comp/day	lb/day	TPY
Valves	600	0.00179	1.074	0.196
Flanges	1800	0.00166	2.988	0.545
Compressors	4	0.28	1.12	0.204
Total			5.182	0.945

The emission factors are based on the CAPCOA correlation equations and screening values. The District approved the use of the CAPCOA correlation equations for determining the mass rate of emissions from fugitive equipment during the recent plant renewal cycle for Valero.

Maximum Annual Emissions

The total emissions from this Power Plant project including the exempt small package wet cooling tower are shown in Table II.

Table II

Phase I - Permitted Maximum Annual Emissions, tons/yr

	NOx	CO	POC	SO2	PM10
GT/HRSG's (S-1030, S-1031)	28.603	41.9285	7.983	15.0	6.803
Fugitives			0.596		
Cooling Tower					0.33
Total	28.603	41.9285	8.579	15.0	7.133

Phase II - Permitted Maximum Annual Emissions, tons/yr

	NOx	CO	POC	SO2	PM10
GT/HRSG's (S-1030, S-1031)	28.603	41.9285	7.983	15.0	6.803
Fugitives			0.349		
Cooling Tower					0.33
Total	28.603	41.9285	8.332	15.0	7.133

Phase I and Phase II - Permitted Maximum Annual Emissions, tons/yr

	NOx	CO	POC	SO2	PM10
GT/HRSG's (S-1030, S-1031 S-1032, S-1033)	57.206	83.857	15.966	30.0	13.606
Fugitives			0.945		
Cooling Tower					0.66
Total	57.206	83.857	16.911	30.0	14.266

Cooling Tower Emission Estimation

A new small package cooling water system will be used to dissipate heat from lube oil and the chiller. There is no steam condensing duty. The refinery's existing cooling tower is located just to the east of the new equipment. The circulation rate for each phase will be 2800 gpm. Makeup cooling water estimated at 35 gallons per minute for each phase will be obtained from the City of Benicia through existing lines. The configuration will be three cells, each of which will be 11 feet in diameter. The maximum air flow rate is 540,000 cfm. The maximum heat dissipation rate will be 40 MM Btu/hr, and the drift rate will be 0.005% of design flow.

Cooling tower PM10 emissions are calculated based on a circulation rate of 2800 gpm of fresh water for each power train, a drift rate of 0.005% of design flow, a total maximum dissolved solids (TDS) concentration of 216 ppmv in the makeup water and 5 cycles of concentration. All TDS emitted is assumed to be PM10. The PM10 is calculated as shown below:

2800 gallons/min x 8.34 lb H2O/gallon = 23,352 lb H2O/min

23,532 lb H20/min x 0.005/100 drift x 216 lb PM10/1,000,000 lb H2O x 5 cycles
x 60 min/hr = 0.076 lb/hr PM10 or 0.33 ton/yr PM10 for each phase of the project

Based on a water analysis from the City of Benicia, the cooling tower will emit the following compounds: Chlorine, Copper, Manganese, Nickel, Sulfate and zinc. As shown in the table below, the emissions from these compounds due to the new cooling tower for PhaseI and Phase II combined, when using fresh water, is estimated to be 0.66 tons/year of particulate matter, with about 4/5 of these emissions coming from sulfates.

Table III

Cooling Tower Emissions (Phase I and Phase II)

Compound	**Cooling Water Rate (gpm)**	**Drift Rate (%)**	**Concentration in Water Emissions[1] (Lb/Hr)**	**Emissions[1] (TPY)**
Chlorine	5600	0.005	2.64E-02	1.157E-01
Copper	5600	0.005	6.08E-06	2.6E-05
Manganese	5600	0.005	7.05E-06	3.09E-05
Nickel	5600	0.005	2.98E-06	1.3E-05
Sulfate	5600	0.005	1.24E-01	5.43E-01
Zinc	5600	0.005	2.4E-06	1.051E-05
Total				6.6E-01

[1]The emissions from the cooling tower were included in the Health Risk Assessment for Valero's Cogeneration Project.

III. STATEMENT OF COMPLIANCE

A. Best Available Control Technology (BACT) Determinations

The following section includes BACT determinations by pollutant for the permitted sources included in the proposed project.

Air Pollution Control Strategies and Equipment

The proposed facility includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2) for emissions of nitrogen oxides (NOx), carbon monoxide (CO), precursor organic compounds (POC), sulfur dioxide (SO2), and particulate matter of less than 10 microns in diameter (PM10) because its emissions of each pollutant are above 10 pounds per highest day [Regulation 2-2-301].

The NOx, CO, and oxygen concentrations will be monitored continuously using a continuous emissions monitor (CEM). Therefore, emission concentrations of NOx and CO will be limited to parts per million (ppm) emissions concentrations in the permit conditions.

Nitrogen Oxides (NOx)

District BACT Guideline 89.1.6, dated October 18, 2000, specifies BACT1 (technologically feasible/cost-effective) for NOx for a combined-cycle gas turbine with a power rating $\geq$ 50 MW. BACT1 is a NOx emissions concentration not to exceed 2.5 ppmvd @ 15% O2, averaged over 1 hour for natural gas firing. This low emissions level has been achieved through the use of Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with combustion modifications. BACT2 (achieved in practice) is a concentration not to exceed 3 ppmvd @ 15% O2 (averaged over 3 hours) when firing natural gas.

Since there is no BACT determination for gas turbines and HRSG's firing refinery fuel gas, a case by case BACT analysis has been performed. The District has determined that BACT for NOx for this project is an SCR system designed and demonstrated to achieve 2.5 ppmvd @ 15% O2 when firing natural gas (one hour average) or when firing refinery fuel gas (three hour average). As discussed in **Appendix B**, the NOx emissions from a GE Frame 7 gas turbine is around 42 ppm. The cost effectiveness analysis was based on the cost effectiveness of installing SCR systems on two GE Frame 7 gas turbines being fired on refinery fuel gas, and controlled using water injection. Using the actual control costs for the larger Frame 7 turbines and the smaller tons controlled for the Valero Cogeneration Project, the estimated cost effectiveness of control to reach 2.5 ppm is $6726, which is less than the District's guideline of $17,500/ton. Hence, it is cost effective and technologically feasible to limit the NOx to 2.5 ppm regardless of the fuel fired in this power plant.

Two relatively new technologies are capable, under some conditions, of controlling NOx emissions from a gas turbine to 2 ppmv or below. These are SCONOx, manufactured by Goal Line Environmental Technologies, and XONON, manufactured by Catalytica, Inc. The District has reviewed these technologies to determine if they are appropriate for this application. SCONOx is the more established of the two technologies. This system uses a potassium carbonate coated catalyst to remove both NOx and CO, without the use a reagent such as ammonia. There is one system in commercial operation on a gas turbine of comparable size to this project. This system has demonstrated that SCONOx can consistently achieve NOx levels comparable to those achieved by SCR on medium-sized (~50 MW) turbines. The District considers this technology equivalent to use of SCR for medium-sized turbines, and would approve a project that proposed its use.

XONON, developed by Catalytica, Inc., is another promising new technology for NOx emissions control. This technology uses a flameless catalyst located inside the combustion chamber itself, which allows for the combustion reaction to proceed at a lower temperature than in conventional turbines, thus minimizing the formation of NOx.

At the present time, the commercial availability of XONON technology is extremely limited. To date, we are aware of only one application, a 1.5 MW turbine in Santa Clara, California. There is no information available regarding the operation of such a system on a turbine the size of the one to be installed at this project, which is over 30 times larger. Based on this information, XONON does not represent a technologically feasible control option for this project.

In summary, XONON is not technologically feasible for this project. SCR and SCONOx are both feasible, and achieve equivalent NOx reductions. The applicant's choice of SCR to meet the BACT control level of 2.5 ppm is therefore acceptable.

SCR: Water will be injected into the turbine combustor to reduce NOx emissions at the combustor exhaust. Aqueous ammonia is injected into the SCR catalyst to control exiting stack emissions. The ammonia slip will be limited by permit condition to 10.0 ppmv. While some recent projects using natural gas have been approved with ammonia slip at 5.0 ppm, the 10 ppm level is reasonable because the variability of refinery gas fuel qualities require some additional allowance for ammonia slip. The only current regulatory basis for controlling ammonia is nuisance, and 10 ppm will not result in either odor nuisance or unacceptable health impacts. SCR for controlling NOx emissions represent a control technology that is technologically feasible, cost-effective, and achieved in practice in a wide variety of applications. This control technology represents BACT for this cogeneration project.

Carbon Monoxide (CO)

District BACT Guideline 89.1.6, dated October 18, 2000, specifies BACT2 (achieved in practice) for CO, firing natural gas, for a gas turbine with a power rating $\geq$ 50 MW, as CO emissions $\leq$ 10.0 ppmvd @ 15% O2, achieved through the use of an oxidation catalyst. CO emissions are also minimized through the use of best combustion practices. BACT1 (technologically feasible/cost-effective) is specified for natural gas as a CO emission concentration of less than or equal to 6 ppmvd @15% O2.

The District has determined that BACT2 (achieved in practice) for this Cogeneration project firing refinery fuel gas or natural gas is 6 ppmvd @ 15% O2. BACT1 has not been determined. The BACT analysis is presented in **Appendix C.** The CO emissions from each combustion turbine train fired on natural gas and/or refinery fuel gas will be reduced through the use of an oxidation catalyst to a CO concentration level not to exceed 6 ppmvd @ 15% O2, averaged over any consecutive three-hour period.

In summary, achieved in practice BACT for CO is deemed to be 6 ppmvd CO @15% O2, averaged over any consecutive three hour period, for the combined exhaust from the gas turbines and HRSG duct burners during all modes of operation, except startup and shutdown. The applicant intends to achieve compliance with this limit through the use of a CO oxidation catalyst (A-61 and A-63).

Precursor Organic Compounds (POCs)

District BACT Guideline 89.1.6, dated 10/18/00, specifies BACT2 (achieved in practice) for POC, on natural gas, for a gas turbine with a power rating $\geq$ 50 MW, as POC emissions $\leq$ 2.0 ppmvd @ 15% O2, achieved through the use of an oxidation catalyst. BACT1 is undefined. The POC emissions from the combustion turbine on natural gas and/or refinery fuel gas will be reduced through the use of an oxidation catalyst to a level not to exceed 2.0 ppmvd POC @ 15% O2.

Because CEMs for organic compounds only measure carbon (as C1), it is not possible to determine non-methane/ethane hydrocarbon concentrations on a real-time basis. As a result, a continuous emission concentration limitation as BACT for POC is not feasible. Therefore, BACT for POC is deemed to be a mass emission rate limitation to be verified by quarterly source testing. The POC emissions from the combustion turbine will be reduced to 2.0 ppmvd or less through the use of an oxidation catalyst. POC emissions are also minimized through the use of good combustion practices.

Sulfur Dioxide (SO_2)

The proposed 102 MW power plant (S-1030, S-1031, S-1032, S-1033) will be fired on refinery fuel gas and natural gas. District BACT Guideline 89.1.6, dated 10/18/00, specifies BACT on natural gas for SO_2 emissions is a sulfur content not to exceed 1.0 grain/100 scf achieved through the use of PUC-regulated grade natural gas. There is no established BACT level for SO_2 when firing refinery fuel gas. Thus, a case-by-case analysis will be performed. To control SO_2 emissions, the sulfur levels in the refinery fuel gas will need to be at the lowest level practicable.

The District has determined that BACT for SO_2 emissions for this project is a fuel gas sulfur level not to exceed 35 ppmv (rolling consecutive 365-day average). The refinery currently routinely achieves this level on refinery gas. Blending with natural gas to maintain this level is feasible. A daily limit will be set at 100 ppm TRS (rolling 24-hour average). To comply with New Source Performance Standards (NSPS), 40 CFR 60 Subpart J, the hydrogen sulfide (H_2S) level in the refinery fuel gas will be limited to no more than 160 ppm H_2S (3 hour average). A detailed analysis is presented in **Appendix C.**

Particulate Matter (PM_{10})

The proposed power plant (S-1030, S-1031, S-1032, S-1033) will be fired on refinery fuel gas as well as natural gas. BACT on natural gas for PM_{10} emissions is a sulfur content not to exceed 1.0 grain/100 scf achieved through the use of PUC-regulated grade natural gas. There is no established BACT level for PM_{10} when firing refinery fuel gas. Thus, a case-by-case analysis will be performed.

The California Air Resources Board (CARB) has published a document titled "Guidance for Power Plant Siting and BACT'' dated July 1999. The document contains PM_{10} source test results for combined cycle and cogeneration gas turbines. This information was provided in Appendix C, Page 45 of that CARB document. As mentioned earlier that page has been excerpted from that document and is shown in **Appendix A**. As shown, two separate source tests were conducted on October 1995 and November 1996 on a General Electric LM 6000 gas turbine with auxiliary-fired HRSG firing natural gas producing 42 MW. The source test results were 1.01 lb/hr and 2.08 lb/hr PM_{10}, respectively.

Extrapolating the higher emissions rate of 2.08 lb/hr to 51 MW yields 2.53 lb/hr PM_{10} for one turbine train, or 5.06 for both. Assuming a 35% higher PM_{10} because of the higher sulfur in the refinery fuel gas (35 ppm) over natural gas (3-6 ppm) yields 3.2 lb/hr PM_{10} for one turbine train, or 6.4 for both. For purposes of PM_{10} modeling, Valero used 4.65 lb/hr PM_{10} for one turbine train, or 9.3 lb/hr for both. For this Cogeneration project, the maximum hourly rate will be based on the values used for modeling of 9.3 lb/hr. As an annual hourly limit, Valero will be limited to no more than 1.55 lbs/hr PM_{10} (calendar year average) for one turbine train or 3.1 lbs/hr for both.

B. Emissions Offsets

Pursuant to Regulation 2, Rule 2, Section 302, federally-enforceable emission reduction credits are required for NOx and POC emissions, minus any contemporaneous emission reduction credits, at a ratio of 1.15: 1.0. Pursuant to Regulation 2, Rule 2, Section 303, federally enforceable emission reduction credits are required for SO2 and PM10 emissions, minus any contemporaneous emission reduction credits, at a ratio of 1.0 to 1.0. Pursuant to Regulation 2, Rule 2, Sections 302 and 303, contemporaneous emissions reductions for NOx, POC, SO2 and PM10 are treated as being at a ratio of 1.0 to 1.0. The applicant has demonstrated that it possesses sufficient valid offsets for this project and will submit certificates before the authority to construct is issued.

<u>NOx Offsets:</u>

The NOx emissions increase from the Cogeneration project is 57.206 tons/year. This offset obligation will be met through providing 29.694 tons/year of total contemporaneous emission reductions (as determined below) and the balance of 31.639 tons/year [27.512 tons/year x 1.15 (offset ratio)] through surrendering banking certificates.

Valero will surrender banking certificate #703 having NOx credits of 31.418 to satisfy, in part, their offset NOx obligation remaining after subtracting the contemporaneous emission reductions. Since Valero does not have enough NOx credits to fully offset Phase I and Phase II (31.639 minus 31.418 = 0.221 tons/yr NOx), POC credits will be provided for the balance in accordance with the NOx offset substitution provision allowed in Regulation 2.2-302.2. Valero will surrender banking certificate #682 having POC credits of 14.769 tons for this purpose.

Banking certificate #703 originated from Application 27578. Emission reduction credits were generated when Valero installed the A-51 Selective Catalytic Reduction (SCR) system to control NOx emissions from the S-37 Steam Generator in 1997. No regulation required that the emissions from this source be abated. Consequently, Valero was issued a banking certificate pursuant to Regulation 2-4-301.1 for emission reductions resulting from the installation of a level of control greater than required by regulation.

Banking Certificate #682 is the residual of Banking Certificate #86 (the original certificate issued in Application 98). Emission reduction credits were generated from the control of POC emissions from Exxon's (now Valero) crude oil lightering operations in the San Francisco Bay. The plant receives most of its crude oil for processing by ship. A portion of this crude is lightered to barges or other small vessels. To control POC lightering emissions from these vessels, the plant installed a vapor balance system, using a flexible vapor line between the lightering vessel to the parent vessel. The control system became operational in June, 1988. The plant was issued Certificate #86 for 122 tons of POC emissions.

Contemporaneous Emission Reductions

Valero intends to shutdown three package boilers (S-38, S-39, S-41) which will no longer be needed to provide steam. The emission reductions from these sources will be used to offset the NOx emissions increase from the Valero Cogeneration Project. To determine the baseline for these boilers, Valero provided District staff with a printout showing the average hourly firing rate for each day for these units from April 1, 1998 to March 31, 2001. Since the baseline period per Regulation 2-2-605 is a three year period immediately preceding the date the application is deemed complete (April 2001), the three-year baseline period is April 1998 through March 2001. The data for the 3-year baseline period is shown in **Appendix D.**

The average hourly firing rate for the S-38 is 72.480 MM Btu/hr. The average hourly firing rate for S-39 is 46.230 MM Btu/hour. The average hourly firing rate for S-41 is 86.730. The NOx emissions factor of 0.2153 Lb/MM Btu for the S-38 boiler is based on a source test by Best Environmental on April 26 and April 27, 2001. This emissions factor will be used for S-38 and S-39 since the boilers are essentially identical. The NOx emissions factor for the S-41 Boiler is based on CEM data acquired during the month of July, 2001. The NOx concentration for this period was 128 ppmv @ 3% O2 resulting in an emissions factor of 0.1481 lb NOx/MM Btu. See **Appendix E** for supporting information on establishment of acceptable emission factors.

Three Package Boilers (S-38, S-39, S-41)
[(72.480 + 46.230) MM Btu/hour x 0.2153 Lb NOx/MM Btu] + [86.730 MM Btu/hour x 0.1481 Lb NOx/MM Btu] x 8760 hours/yr x ton/2000 Lb = **168.205 tons/year** actual emission reduction

To qualify as contemporaneous emission reduction credits (for PSD threshold calculations), the actual emission reductions must be adjusted for RACT. NOx RACT for refinery boilers is 0.2 lb/MM btu (9-10-303). The RACT adjusted NOx contemporaneous emission reduction credits are therefore:
[(72.480 + 46.230) MM Btu/hour x 0.2 Lb NOx/MM Btu] + [86.730 MM Btu/hour x 0.1481 Lb NOx/MM Btu] x 8760 hours/yr x ton/2000 Lb = **160.250 tons/year** contemporaneous emission reduction

BARCT Adjustment

To qualify as an emission reduction pursuant to Regulation 2-2-201, the emission reduction must be in excess of the reduction required by District laws, rules and regulations. District Regulation 9, Rule 10 limits emissions of NOx from boilers. Pursuant to Section 9-10-301, the limit is 0.033 lb/MM Btu. Therefore, the allowable reduction is:

Three Package Boilers (S-38, S-39, S-41)
Phase I, S-38 and S-39: (72.480 + 46.230) MM Btu/hour x 0.033 lb NOx/MM Btu x 8760 hours/yr x ton/2000 Lb = **17.158 tons/year NOx**

Phase II, S-41: 86.730 MM Btu/hour x 0.033 lb NOx/MM Btu x 8760 hours/yr x ton/2000 Lb = **12.536 tons/year NOx**

The total contemporaneous emission reductions are **29.694 tons/year NOx** (17.158 + 12.536). Tables V, VI and VII that appear later systematically lays out the manner for which Valero will meet the NOx offset obligation in each phase.

<u>SO2 Emissions Offset:</u>

The Cogeneration project will generate up to 30 tons per year of SO2 emissions. All emissions from the two new turbine trains will be offset by either contemporaneous emission reduction (shut down of replaced boilers and elimination of MTBE ships) or simultaneous emissions reductions (reduction in usage at other sources within the curtailment group.) As shown in Table IV, all sources folded into this curtailment group will have a combined limit not to exceed 34.75 tons/year of SO2 emissions. The baseline emissions from existing sources in the curtailment group (S-40, S-220, S-237, MTBE ships) are 30.09 tons/year SO2 emissions and contemporaneous emission reductions (S-38, S-39 and S-40) make up 4.66 tons/year of SO2 emissions. The two new turbine trains have a baseline of zero. Compliance with this bubble results in a net SO2 increase from this Cogeneration project of zero. Discussion on the curtailment group and the contemporaneous emission reduction from the three boilers are presented below:

Curtailment Group

Valero does not have any SO2 Emission Reduction Credits (ERC's) beyond contemporaneous ERC's from boiler shutdowns (S-38, S-39 and S-41). The SO2 emissions reductions from the boiler shutdowns are 4.66 tons/year. Valero reports that attempts to purchase deposited SO2 credits from third parties has been fruitless. Due to the unavailability of SO2 credits in the Bay Area, Valero proposes to provide SO2 offsets by curtailing SO2 emissions from a specified group consisting of several sources including the proposed Cogeneration Project turbines and HRSGs. This group of sources will form an SO2 emissions "bubble". The group baseline for the sources other than the proposed Cogeneration Project sources is determined using the District procedures in Section 2-2-605 for calculating ERC baselines. The entire curtailment group will be managed to insure that there is no net increase in SO2 emissions above the group baseline after the new cogeneration project facilities are installed. Reductions from curtailment of curtailment group heaters must be real. Reduction in use of a curtailment group source must not be circumventable by increase in emissions from another source in the refinery outside the curtailment group. The curtailment group and baseline for this bubble are shown below.

<u>BOILERS:</u> In order to ensure that reductions in steam produced by curtailment group boilers is not replaced by increases from the refinery steam sources, all of the package boilers in the refinery have been included in the curtailment group. Every other source of steam in the refinery is generated by a waste heat recovery process and therefore determined by process demands, not steam needs.

Table IV

Curtailment Group: Emission Sources	SO2 Baseline, Tons/year	Basis
Total Group Baseline		
S-237 Steam Boiler SG1032	8.6	Emissions fully offset (App. #18888)
S-220 Hot Oil Furnace F 4460	10.0	Emissions fully offset (App.#10392)
MTBE Ships	9.5	Emissions fully offset (App. #10392)
S-40 Boiler SG2301	1.99[1]	Three Year Baseline (App. #2695)
Phase I		
New GT/HRSG (S-1030 & S-1031)	0.0	New Source – Zero Baseline
Phase II		
New GT/HRSG (S-1032 & S-1033)	0.0	New Source – Zero Baseline
	30.09	
Offsets Provided (baseline shutdowns)		
S-38 Boiler SG703	1.61[1]	Three Year Baseline (App. #2488)
S-39 Boiler SG2901	1.10[1]	Three Year Baseline (App. #2488)
S-41 Boiler SG2302	1.95[1]	Three year baseline (App. #2695)
	4.66	
Total	34.75	Group Annual Limit

[1]SO2 emissions baseline calculations for the four boilers (S-38, S-39, S-40, S-41) are included in Appendix D.

To qualify as an emission reduction pursuant to Regulation 2-2-201, the emission reduction must be in excess of the reduction achieved by, or achievable by, the source using Reasonably Available Control Technology (RACT). RACT is 160 ppm H2S averaged over any consecutive three hour period. All of these sources comply with current Reasonably Available Control Technology (RACT) requirements. Therefore, no RACT adjustment of baseline emissions is required.

Tables V, VI and VII that appear later systematically lays out this bubble approach for each phase.

POC emissions offset:
The project emissions increase for POC is 16.911 tons/year, which includes 0.945 tons/year from fugitive equipment (valves, flanges and compressors). This offset obligation will be met through providing 10.475 tons/year of total contemporaneous emission reductions (as determined below) and the balance of 7.401 tons/year [6.436 tons/year x 1.15 (offset ratio)] tons/year through surrendering a banking certificate.

Valero will surrender banking certificate #682 having credits of 14.769 tons of POC emissions to offset 7.401 tons/year. Valero will be issued another banking certificate for the unused emission reduction credits [14.769–7.401-0.221 (used for NOx offsets above) = 7.147 tons of POC].

Banking Certificate #682 is the residual of Banking Certificate #86 (the original certificate issued in Application 98). Emission reduction credits were generated from the control of POC emissions from Exxon's (now Valero) crude oil lightering operations in the San Francisco Bay. The plant receives most of its crude oil for processing by ship. A portion of this crude is lightered to barges or other small vessels. To control POC lightering emissions from these vessels, the plant installed a vapor balance system, using a flexible vapor line between the lightering vessel to the parent vessel. The control system became operational in June, 1988. The plant was issued Certificate #86 for 122 tons of POC emissions.

Contemporaneous Emission Reductions
The average hourly firing rate for the S-38 is 72.480 MM Btu/hr. The average hourly firing rate for S-39 is 46.230 MM Btu/hour. The average hourly firing rate for S-41 is 86.730. The POC emissions factor for S-38 and S-39 is 0.02 lb/MM Btu. The POC emissions factor for S-41 is 0.0002 lb/MM Btu. These factors came from source tests conducted on S-38 and S-41 by Best Environmental on April 26 and April 27, 2001. The emission factor for S-38 was used for S-39 since the two boilers are essentially identical. See **Appendix E**.

Three Package Boilers (S-38, S-39, S-41)
Phase I, S-38 and S-39: [(72.480 + 46.230) MM Btu/hour x 0.02 lb POC/MM Btu x 8760 hours/yr x ton/2000 Lb = **10.399 tons/year POC**
Phase II, S-41: 86.730 MM Btu/hr x 0.0002 lb POC/MM Btu x 8760 hours/yr x ton/2000 Lb = **0.076 tons/year POC**
The total emission reductions are **10.475 tons/year POC** (10.399 + 0.076).

To qualify as an emission reduction pursuant to Regulation 2-2-201, the emission reduction must be in excess of the reduction achieved by, or achievable by, the source using Reasonably Available Control Technology (RACT). RACT is good combustion practices. All of these sources comply with current RACT requirements. Therefore, no RACT adjustment of baseline emissions is required. Tables V, The tables that appear later systematically lays out the manner for which Valero will meet the POC offset obligation in each phase.

PM10 Emissions Offset:

The project emissions increase for PM10 is 14.266 tons/year, which include 0.66 tons/year from the exempt cooling tower. Per Regulation 2-2-303, the 0.66 ton/year of PM10 emissions from the exempt cooling tower in Phase I and Phase II combined is not subject to offsets since it is neither a permittable new or modified source. However, the CEC is requiring Valero to offset the PM10 emissions from the exempt Cooling Tower because of PSD concerns.

The project will be fully offset through contemporaneous emission reduction credits stemming from the shutdown of three boilers (S-38, S-39 and S-40). The total reductions from these boilers amount to 15.477 tons/year. Hence, the project results in a net decrease 1.211 tons/year.

Tables V, VI and VII that appear later systematically lays out the manner for which Valero will meet the PM10 offset obligation in each phase.

PM10 Contemporaneous Emission Reductions

The average hourly firing rate for the S-38 is 72.480 MM Btu/hr. The average hourly firing rate for S-39 is 46.230 MM Btu/hour. The average hourly firing rate for S-41 is 86.730 MM Btu/hr. The PM10 emissions factor for S-38 and S-39 is 0.021 lb/MM Btu. The PM10 emissions factor for S-41 is 0.012 lb/MM Btu. These factors came from source tests conducted on S-38 and S-41 by Best Environmental on April 26 and April 27, 2001. The emissions factor for S-38 is being used for S-39 since the boilers are essentially identical. See test results in **Appendix E**.

Three Package Boilers (S-38, S-39, S-41)
Phase I, S-38 and S-39: [(72.480 + 46.230) MM Btu/hour x 0.021 lb PM10/MM Btu x 8760 hours/yr x ton/2000 Lb = **10.919 tons/year PM10**
Phase II, S-41: 86.730 MM Btu/hr x 0.012 lb PM10/MM Btu x 8760 hours/yr x ton/2000 Lb = **4.558 tons/year PM10**

The total contemporaneous reductions for PM10 are **15.477 tons/year PM10** (10.919 + 4.558).

All of these sources comply with current RACT requirements. Therefore, no RACT adjustment of baseline emissions is required.

CO Emissions (No Offset Requirement):

The Cogeneration project increase for CO emissions is 83.857 tons per year. Unlike the aforementioned pollutants, there is no offset requirement per District regulation for CO emissions. For purposes of continuity with the preceding pollutants and for purposes of Prevention of Significant Deterioration (PSD), the contemporaneous emission reductions for CO due to the shutdown of the three boilers (S-38, S-39 and S-41) are presented below.

Contemporaneous Emissions Reduction

The average hourly firing rate for the S-38 is 72.480 MM Btu/hr. The average hourly firing rate for S-39 is 46.230 MM Btu/hour. The average hourly firing rate for S-41 is 86.730. The CO emissions factor for S-38 and S-39 is 0.4914 lb/MM Btu. These factors came from source tests conducted on S-38 and S-41 by Best Environmental on April 26 and April 27, 2001. See **Appendix E**. The CO emissions factor for S-41 is minimal based on source test. The emission factor for S-38 was used for S-39 since the two boilers are essentially identical. Valero has chosen not to seek any CO emissions reduction from S-41.

Three Package Boilers (S-38, S-39, S-41)
Phase I, S-38 and S-39: [(72.480 + 46.230) MM Btu/hour x 0.4914 lb CO/MM Btu] x 8760 hours/yr x ton/2000 Lb = **255.503 tons/year CO**
Phase II, S-41: 0 tons/year (Valero seeks no credit)

BARCT Adjustment
To qualify as an emission reduction pursuant to Regulation 2-2-201, the emission reduction must be in excess of the reduction required by District laws, rules and regulations. Per District Regulation 9, Rule 10, CO emissions from boilers are limited to 400 ppm @ 3% O_2 or 0.287 lb CO/MM Btu (Section 9-10-305). Therefore, the allowable emissions reduction is:

Phase I, S-38 and S-39: [(72.480 + 46.230) MM Btu/hour x 0.287 lb CO/MM Btu] x 8760 hours/yr x ton/2000 Lb = **149.225 tons/year CO**
Phase II, S-41: 0 tons/year (Valero seeks no credit)

The total contemporaneous reductions for CO are **149.225 tons/year CO** (149.225 + 0.0).

For purposes of completeness, the CO emissions are included also in Tables V, VI and VII.

Table V

PHASE I OFFSETS REQUIRED

Phase I Emissions Increases and decreases

	NOx	CO	POC[1]	SO2	PM10
GT/HRSG's (S-1030, S-1031)	28.603	41.9285	7.983	15.0	6.803
Fugitives			0.596		
Cooling Tower					~~0.33~~[1]
Total	28.603	41.9285	8.579	15.0	6.803

[1]Per Regulation 2-2-303, the 0.33 ton/year of PM10 emissions from the exempt cooling tower in Phase I is not subject to offsets since it is neither a permittable new or modified source. However, the CEC is requiring Valero to offset the PM10 emissions from the exempt Cooling Tower because of CEQA mitigation.

Contemporaneous Emissions Reduction

	NOx	CO	POC	SO2	PM10
S-38, S-39	-17.158	-149.225	-10.399	-2.71	-10.919
Total	-17.158	-149.225	-10.399	-2.71	-10.919

Simultaneous Emissions Reduction

	NOx	CO	POC	SO2	PM10
S-40, S-220, S-237, MTBE				-30.09	
Total				-30.09	

Remaining Offsets Needed

	NOx	CO	POC	SO2	PM10
GT/HRSG Fugitives	11.445	N/A	-1.820	0.0	-4.116
Offset Ratio	1.15	N/A	1.15	1.0	1.0
Total	13.162[1]	N/A	credit[2]	0.0[3]	Credit[4]

[1]Valero will surrender banking certificate #703 having NOx credits of 31.418 to satisfy this offset obligation. The remaining balance of 18.256 tons of NOx (31.418 minus 13.162) will be applied to Phase II. If Phase II is not constructed, another banking certificate for the balance of 18.256 tons of NOx emissions will be issued back to Valero

[2]Phase I generated a POC credit of 1.820 tons/year. Credit will be applied to Phase II. If Phase II is not constructed, Valero has requested that the District issue a banking certificate for the excess POC emissions reductions credits in accordance with Regulation 2-2-606.

[3]All emissions from the new turbine train will be offset by either contemporaneous emission reduction (shutdown of replaced boilers and elimination of MTBE ships) or simultaneous emissions reductions (reduction in usage at other sources within the curtailment group.) All emissions folded into this curtailment group will be limited to no more than 34.75 tons/year of SO2 emissions.

[4]Phase I will generate a PM10 credit of 4.116 tons/year. Credit will be applied to Phase II. If Phase II is not constructed, Valero has requested that the District issue a banking certificate for the excess PM10 emissions reduction in accordance with Regulation 2-2-606. In the event a banking certificate is issued for this situation, the District will withhold 0.33 ton/year of PM10 credits to offset the PM10 emissions from the exempt Cooling Tower as required by the CEC. Valero will be issued another banking certificate for the unused emission reduction credits [4.116 – 0.33] = 3.786 tons of PM10.

Table VI

PHASE II OFFSETS REQUIRED

Phase II Emissions Increases and decreases

	NOx	CO	POC	SO2	PM10
GT/HRSG's (S-1032, S-1033)	28.603	41.9285	7.983	15.0	6.803
Fugitives			0.349		
Cooling Tower					~~0.33~~[1]
Total	28.603	41.9285	8.332	15.0	6.803

[1]Per Regulation 2-2-303, the 0.33 ton/year of PM10 emissions from the exempt cooling tower in Phase II is not subject to offsets since it is neither a permittable new or modified source. However, the CEC is requiring Valero to offset the PM10 emissions from the exempt Cooling Tower because of CEQA mitigation.

Contemporaneous Emissions reduction Credits

	NOx	CO	POC	SO2	PM10
S-41	-12.536	0.0	-0.076	-1.95	-4.558
S-38 and S-39 Phase I leftover		0.0	-1.820		-4.116
Total	-12.536	-0.0	-1.896	-1.95	-8.674

Simultaneous Emissions Reduction

	NOx	CO	POC	SO2	PM10
S-40, S-220, S-237, MTBE				-30.09	
Total				-30.09	

Remaining Offsets Needed

	NOx	CO	POC	SO2	PM10
GT/HRSG Fugitives	16.067	N/A	6.436	0.0	-1.871
Offset Ratio	1.15	N/A	1.15	1.0	1.0
Total	18.477[1]	N/A	7.401[2]	0.0[3]	Credit[4]

[1]Valero will surrender banking certificate #703 having leftover NOx credits of 18.256 tons/year after Phase I deductions. Since Valero does not have enough NOx credits to fully offset the Phase II NOx emissions (18.477 minus 18.256 = 0.221 tons/yr NOx), POC credits will be provided for the balance in accordance with the NOx offset substitution provision allowed in Regulation 2.2-302.2. Valero will surrender banking certificate #682 having POC credits of 14.769 tons for this purpose.

[2]Valero will surrender banking certificate #682 having credits of 14.769 tons of POC emissions. Valero will be issued another banking certificate for the unused emission reduction credits [14.769–7.401-0.221 (for NOx)] = 7.147 tons of POC].

[3]All emissions from the new turbine train will be offset by either contemporaneous emission reduction (shutdown of replaced boilers and elimination of MTBE ships) or simultaneous emissions reductions (reduction in usage at other sources within the curtailment group.) All emissions folded into this curtailment group will be limited to no mre than 34.75 tons/year of SO2 emissions.

[4]Phase I and Phase II combined will generate a PM10 credit of 1.871 tons of PM10 emissions. Valero has requested that the District issue a banking certificate for the excess PM10 emissions reduction credit in accordance with Regulation 2-2-606. In the event a banking certificate is issued in this situation, the District will withhold 0.66 tons/year pf PM10 credits to offset the PM10 emissions from the exempt Cooling Tower as required by the CEC. Valero will be issued another banking certificate for the unused emission reduction credits [1.871 – 0.66] = 1.211 tons of PM10 after the three boilers (S-38, S-39 and S-41) have been shut down.

Table VII
PHASE I and PHASE II OFFSETS REQUIRED

Phase I and Phase II Emissions Increases and decreases

	NOx	CO	POC	SO2	PM10
GT/HRSG's (S-1030, S-1031 S-1032, S-1033)	57.206	83.857	15.966	30.0	13.606
Fugitives			0.945		
Cooling Tower					~~0.66~~[1]
Total	57.206	83.857	16.911	30.0	13.606

[1]Per Regulation 2-2-303, the 0.66 ton/year of PM10 emissions from the exempt cooling tower because of Phase I and Phase II is not subject to offsets since it is neither a permittable new or modified source. However, the CEC is requiring Valero to offset the PM10 emissions from the exempt Cooling Tower because of CEQA mitigation..

Contemporaneous Emissions Reduction Credits

	NOx	CO	POC	SO2	PM10
S-38, S-39, S-41	-29.694	-149.225	-10.475	-4.660	-15.477
Total	-29.694	-149.225	-10.475	-4.660	-15.477

Simultaneous Emissions Reductions

	NOx	CO	POC	SO2	PM10
S-40, S-220, S-237, MTBE ships				-31.09	-15.477
Total				-31.09	-15.477

Remaining Offsets Needed

	NOx	CO	POC	SO2	PM10
GT/HRSG Fugitives	27.512	N/A	6.436	0.0	-1.871
Offset Ratio	1.15	N/A	1.15	1.0	1.0
Total	31.639[1]	N/A	7.401[2]	0.0[3]	-1.871[4]

[1]Valero will surrender banking certificate #703 having NOx credits of 31.418 to satisfy this offset NOx obligation. Since Valero does not have enough NOx credits to fully offset Phase I and Phase II (31.639 minus 31.418 = 0.221 tons/yr NOx), POC credits will be provided for the balance in accordance with the NOx offset substitution provision allowed in Regulation 2.2-302.2. Valero will surrender banking certificate #682 having POC credits of 14.769 tons for this purpose.

[2]Valero will surrender banking certificate #682 having POC credits of 14.769 tons. Valero will be issued another banking certificate for the unused emission reduction credits [14.769 –7.401-0.221 (for NOx)] = 7.147 tons of POC].

[3]All emissions from the two new turbine trains will be offset by either contemporaneous emission reduction (shutdown of replaced boilers and elimination of MTBE ships) or simultaneous emissions reductions (reduction in usage at other sources within the curtailment group.) All emissions folded into this curtailment group will be limited to no more than 34.75 tons/year of SO2 emissions. The baseline emissions from existing sources in the curtailment group (S-40, S-220, S-237, MTBE ships) are 30.09 tons/year SO2 emissions and contemporaneous emission reductions (S-38, S-39 and S-40) make up 4.66 tons/year of SO2 emissions. The two new turbine trains have a baseline of zero. Compliance with this bubble results in a net SO2 increase from this Cogeneration project of zero.

[4]Phase I and Phase II combined will generate a PM10 credit of 1.871 tons of PM10 emissions. Valero has requested that the District issue a banking certificate for the excess PM10 emissions reduction credit in accordance with Regulation 2-2-606. In the event a banking certificate is issued in this situation, the District will withhold 0.66 tons/year of PM10 credits to offset the PM10 emissions from the exempt Cooling Tower as required by the CEC. Valero will be issued another banking certificate for the unused emission reduction credits [1.871 – 0.66] = 1.211 tons of PM10 after the three boilers (S-38, S-39 and S-41) have been completely shut down.

C. PSD Air Quality Air Impact Analysis

The Valero Refinery is a major facility under Section 2-1-204.1 because it has the potential to emit more than 100 tons/year of a regulated air pollutant. The Valero Cogeneration Project could be a "major modification" under Section 2-2-221 because the NOx emissions increase from the Cogeneration project, prior to including any contemporaneous emission reductions, will exceed 40 tons/year..

Because the Valero Cogeneration Project is potentially a major modification of a major facility under District regulations, the cumulative impact analysis under Section 2-2-304 must be performed. If the facility's cumulative increase minus contemporaneous emissions reduction credits exceeds the relevant threshold, a Prevention of Significant Deterioration (PSD) analysis must be performed.

In order to determine whether or not the PSD requirement (Section 2-2-304) is triggered, the cumulative increase (emissions increases occurring at the facility for the last five years preceding the date of application completeness minus contemporaneous emission reduction credits) must be determined.

Under Regulation 2-2-302 and 303, Valero has been required since April 5, 1991 to offset emission increases, for all pollutants except CO, at the refinery before permits may be granted. All previously provided offsets qualify as contemporaneous emission reduction credits for purposes of the PSD requirement calculation. Therefore, Valero's cumulative increase minus contemporaneous emission increases "balance" is zero for all pollutants except CO.

This project does not exceed any PSD threshold that would require a PSD permit. Table VIII lists the criteria pollutants for the project and shows that there is no net increase for any of the pollutants. The contemporaneous emissions reduction resulting from the Cogeneration Project will occur from the shutdown of three boilers (S-38, S-39 and S-41). The SO2 reductions come from the previously described curtailment group. Even without the curtailment group offsets, the maximum project emissions of 30 tons/year do not exceed the PSD threshold.

Table VIII
PSD REQUIREMENT APPLICABILITY DETERMINATION[1]

Pollutant	Nitrogen Oxides (NOx) TPY	Carbon Monoxide (CO) TPY	Sulfur Dioxide (SO2) TPY	ParticulateMatter < 10 microns (PM10) TPY	Lead (Pb) TPY
Project Emissions Increase	57.2	83.857	30.0	14.3	0.0086
Project Contemporaneous Emission Reductions	-160.3	-149.6	-30.0	-15.5	0.0
Project Net	-103.1	-65.743	0.0	-1.2	0.0086
Pre-existing Cumulative Increase (5 years preceding April 2001)	0.0	44.7	0.0	0.0	0.0
Cumulative Increase minus Project Net	-103.1	-21.043	0.0	-1.2	0.0086
PSD Trigger (TPY)	40	100	40	15	0.6
PSD Trigger ed?	No	No	No	No	No

[1]Includes emissions from two gas turbines and heat recovery steam generators plus exempt cooling tower

Even though modeling is not required by District regulation, the California Energy Commissions required emission impact modeling for NOx, SO2, PM10 and CO. The modeling results are presented in **Appendix F**. The results show that the cogeneration project will not interfere with the attainment or maintenance of any national ambient air quality standard (NAAQS). The pre-project PM10 background of 83.7 micrograms/cubic meter is in non-attainment with the State 24-hour PM10 standard. Even though the California Ambient Air Quality Standard (CAAQS) for PM10 is already exceeded in the area, an impact of less than the instrument threshold concentration of 5 micrograms/cubic meter over a 24-hour period (project impact is 2.8 micrograms/cubic meter over a 24 hour period) is allowed. Nonetheless, the PM10 emissions for this Cogeneration project, including those from the exempt Cooling Tower, will be fully offset by the shutdown of three package steam boilers (S-38, S-39 and S-41).

PSD for Lead

Lead (Pb) emissions from the project will be less than the PSD threshold of 0.6 ton/year. The estimated lead emissions for the Cogeneration project is 0.0043 ton/year for one turbine train or 0.0086 ton/year for both turbine trains. Lead is particulate. The pre-existing cumulative increase over the last five years is zero since particulate emissions from new and modified sources at Valero are required to be fully offset (Regulation 2-303).

PSD for Mercury and Beryllium

Mercury (Hg) and beryllium (Be) emissions from the project will be less than the PSD threshold of 0.1 and 0.0004 ton/year.

To the District's knowledge, Beryllium has never been detected in the exhaust of a refinery combustion device. A source test performed at Valero in 1996 also failed to detect beryllium. The standard methodology used by California agencies for emission estimates of toxic compounds is described in CARB's Emission Inventory Criteria and Guidelines Report, May 15, 1997. Treatment of values below the limit of detection (LOD) is described on page B-II-21-22.

When all test results are below LOD, the emission rate is reported as zero. This is the case for beryllium. Mercury was also below LOD for the 1996 Valero test. Mercury has, however, been detected in the source tests reported in the CARB database. Where some tests detected a compound, and it is therefore reasonable to expect the compound to be present, test results below the LOD are treated as values of one-half the LOD in the CARB document. The LOD for mercury for the 1996 Valero test was 0.046 μg/dscm. Assuming emissions at half the LOD (0.023 μg Hg/dscm), Valero's projected mercury emissions would be:

Given: Hg mass emissions rate: 0.023 μg/dscf
F-Factor for gas: 8600 dscf/MM Btu
Project Maximum Firing Rate: 1620 MM Btu/hr

0.023 μg Hg/dscm x 8600 dscf/MMBtu x 1620 MM Btu/hr x 0.028317 m^3/ft^3
x 2.205 E-9 lb/μg = 2.0×10^{-5} lb/hr = 0.00009 tons/year Hg

PSD FOR SULFURIC ACID MIST

The sulfuric acid mist (H2SO4) emissions will be conditioned to be less than the PSD threshold of 7 tons per year. The applicant has accepted an enforceable permit condition (Number 20) limiting sulfuric acid mist from the new combustion units to a level below the PSD trigger level. Compliance will be determined by use of emission factors (using fuel gas rate and sulfur content as input parameters) derived from quarterly compliance source tests. The quarterly source test will be conducted, as indicated in Condition number 21, to measure SO2, SO3, H2SO4 and ammonium sulfates. This approach is necessary because the extent of conversion in turbines of fuel sulfur to SO3, and then to H2SO4 is not well established.

D. Health Risk Assessment

A health risk assessment was conducted and reviewed by District staff. The health risk analysis considered toxic emissions from both turbine/HRSG trains and the cooling tower. The maximum potential lifetime cancer risk for this project is estimated to be insignificant, i.e., less than 1.0E-06 (1.0 in one million). The results of the HRA are provided in **Appendix G** and are summarized below.

	Cancer Risk Maximum Screening Value[1]	**Maximum Chronic Hazard Index**	**Maximum Acute Hazard Index**
Total Risk	**0.9 E-06**	**0.1**	**0.03**
Significance criteria	**1.0 E-06**	**1.0**	**1.0**

[1]Cancer risk based on the average of five years of data

Publication and Public Comment

The Final Determination of Compliance (FDOC) is subject to the publication and public comment requirements of sections 2-2-406 and 2-2-407 per section 2-3-404. The District published and solicited comments on the PDOC. We considered all comments made on the PDOC during the public comment period. Many of these comments have been incoporated into this FDOC. In addition, the CEQA process led by the California Energy Commission included hearings to allow the public to provide comments on the project.

CEQA Analysis

The California Energy Comission (CEC) is the Lead Agency under the California Environmental Quality Act (CEQA). The District will not authorize the installation or operation of any proposed new or modified source, the permitting of which is subject to CEQA, until all of the requirements of CEQA have been satisfied. Per District Regulation 2-1-310, this project is not exempt from the requirements of CEQA because it is not ministerial and it is not an exempted source category.

To fulfill the CEQA-related information requirements of District Regulation 2-1-426.2.6, the applicant has submitted to the District information that shows that the CEC has assumed the role of Lead Agency for this project with respect to CEQA.

Valero filed the original Application for Certification (AFC) for Phase I and Phase II of the Valero Power Plant Project on May 7, 2001. The CEC staff has completed its independent data discovery and analysis phases. These phases included a number of public workshops and hearings The CEC's overall review process is expected to be completed within four months from June 6, 2001, the date that the AFC was determined to be data adequate, unless a later date is agreed to by the CEC and the applicant. The planned completion date for the CEC is on or about October 6, 2001.

Environmental Impacts of Ammonia Slip from the Use of SCR:

Aqueous ammonia will be used as the reagent in the SCR system. Deliveries will be made by tanker trucks and stored in an existing 546,000-gallon aboveground storage tank. Gas turbines using SCR have typically had ammonia slip limited to 10 ppmv. However single-digit levels for ammonia slip have been proposed and guaranteed by some control equipment vendors for large combined-cycle gas turbines.

In the June 1999 California Air Resources Board (CARB) "Guidelines for Power Plant Siting and Best Available Control Technology", CARB staff stated that "To date, Massachusetts has permitted two large gas turbine power plants using SCR with 2 ppmvd ammonia slip limits. Given the potential for health impacts and increase in PM10 and PM2.5, districts should ensure that ammonia emissions are minimized from projects using SCR. CARB recommended that districts consider establishing ammonia slip levels below 5 ppmvd at 15% oxygen in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip."

The District is not aware of any such ammonia slip guarantees for combined-cycle turbines that are required to meet a stringent limit of 2.5 ppmv NOx @ 15% O2, averaged over 1 hour, at the same time as meeting the strict limit of 5.0 ppmv ammonia slip when firing natural gas. Since Valero will be firing refinery fuel gas, data in this type of service is limited and the degree of ammonia slip in this type of service is speculative.

A health risk assessment by the District using air dispersion modeling showed an acute hazard index of 0.3 and a chronic hazard index of 0.1 which included the ammonia slip emissions. In accordance with the District Toxic Risk Management Policy, an acute hazard index of less than 1.0 and a chronic hazard index of less than 1.0 are considered acceptable. Therefore, the toxic impact of the ammonia slip at 10 ppm resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to set an ammonia slip limit at 5ppmvd.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulate, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the District's Planning Division, that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter. This potential environmental impact is not considered a sufficient reason to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The applicant will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases. The RMP provides information on the hazards of the substances handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. Therefore, the potential environmental impact due to aqueous ammonia storage at this facility does not justify the elimination of SCR as a control alternative.

E. Other Applicable District Rules and Regulations

Regulation 1, Section 301: Public Nuisance

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District.

Regulation 2, Rule 1, Sections 301 and 302:
Authority to Construct and Permit to Operate

Pursuant to Regulation 2-1-301 and 2-1-302, the applicant has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-1030 Gas Turbine train and S-1032 Gas Turbine Train.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-101, this rule applies to power plants for which a Notice of Initiation or Application for Certification has been accepted by the California Energy Commission (CEC). On May 4, 2001, Valero submitted an Application for Certification (AFC) for Phase I and Phase II of the Power Plant Project. The CEC has assigned the project Docket No. 01-AFC-5 and conducted a hearing for data adequacy on June 6, 2001.

PUBLIC COMMENT: In accordance with BAAQMD Regulation 2, Rule 3, Section 404, the PDOC was subject to the public notice and public inspection requirements of District Regulation 2, Rule 2, Sections 406 and 407. The PDOC was made available for public comment on August 20, 2001. Comments were received from CURE, EPA, City of Benicia, two members of the public and the applicant. The public comment period closed on September 20, 2001.

Regulation 2, Rule 7: Acid Rain

Per the definition of Phase II Acid Rain Facility in Regulation 2-6-217.1, this facility, when both project phases are installed, is a Phase II Acid Rain Facility. Regulation 2-6-302 requires that the facility shall undergo major facility review in accordance with the requirements of this rule, even if such facility is not classified as a major facility under Section 2-6-212. All Phase II acid rain facilities shall comply with the requirements of Sections 405, 406, 408, 409, 411, and 412 of this rule.

This project, when both project phases are installed, will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72, 73, and 75. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are contained in 40 CFR Part 75.

District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72 and administers the program in concert with the Title V Operating Permits Program (Rule 2-6).

The facility must obtain an Acid Rain Permit from the District prior to the date on which the second unit (Phase II) commences operation. The District has been delegated authority for Acid Rain permits by EPA.

The project, when both project phases are installed, will be subject to the following general requirements under the acid rain program:

- Duty to apply for an Acid Rain Permit.
- Compliance with SO2 and NOx emission limits.
- Duty to obtain required SO2 allowances.
- Duty to install, operate and certify Continuous Emission Monitoring Systems (CEMs) to demonstrate compliance with the acid rain requirements.

The applicant will meet the SO2 allowances and will perform the required emission monitoring. Monitoring plans will be submitted as required by EPA rules.

Regulation 6: Particulate Matter and Visible Emissions

Through the use of water-injected low-NOx burner technology and proper combustion practices, the combustion of refinery fuel gas at the proposed gas turbine is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume.

Regulation 7: Odorous Substances

Regulation 7-302 prohibits the discharge of odorous substances which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia emissions from the proposed SCR system will each be limited by permit condition to 10 ppmvd @ 15% O2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: Rule 18 Equipment Leaks

The equipment should comply with the Standards of Regulation 8, Rule 18 for Valves, Compressors and Flanges. The leak standards for valves, compressors and flanges will be 100 ppm, 500 ppm and 100 ppm, respectively.

VALVES -- Most valves will use graphite packing which is the best material available to achieve low emissions in a wide variety of applications. All valves will be required to meet a leak rate of no more than 100 ppm.

COMPRESSORS -- The compressors will be equipped with double mechanical seals and operated in accordance with an approved Inspection and Maintenance (I&M) Program to reduce emissions from compressors seals. A leak standard of 500 PPM will be required to be met.

FLANGES -- The flanges will use graphite or equivalent designed flange gaskets to reduce POC fugitive emissions. A leak standard of 100 PPM will be required to be met.

Regulation 9: Inorganic Gaseous Pollutants

<u>Regulation 9, Rule 1, Sulfur Dioxide</u>

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions which would result in ground level SO2 concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Section 302 (General Emission Limitation) prohibits SO2 emissions in excess of 300 ppm (dry). The gas turbine is not expected to contribute to noncompliance with ground level SO2 concentrations and should easily comply with section 302.

<u>Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations</u>

The proposed combustion gas turbine shall comply with the Regulation 9-3-303 NOx limit of 125 ppm @ 15% O2.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because the proposed combustion gas turbine will be limited by permit condition to NOx emissions of 2.5 ppmvd @ 15% O2, when firing refinery gas, it is expected to comply with the Regulation 9-9-301.3 NOx limitation of 9 ppmvd @ 15% O2.

Regulation 9, Rule 11, Nitrogen Oxides and Carbon Monoxide from Electric Power Generating Steam Boilers

This rule does not apply per the exemption in Regulation 9-11-14.

Regulation 10: New Source Performance Standards (NSPS)

This regulation incorporates the federal NSPS.

Subpart A General Provisions provides the general framework for NSPS. Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units does apply because this project utilizes duct burners. The NOx limit of 85 ppm will easily be met.

Subpart GG Standards of Performance for Stationary Gas Turbines - contains a NOx emission limit in part 60.332 (a)(2) of 50 ppmv at 15% O2, dry, 3-hour average, as well as monitoring and testing requirements for combustion turbines. The project emissions will be well below the applicable NOx emissions limits. The applicant will comply with emission and fuel monitoring requirements, and monitoring plans will be submitted, as required.

Section 112 of the Clean Air Act, National Emission Standards for Hazardous Air Pollutants (NESHAP)

These standards are contained in 40 CFR Parts 61 and 63 and are not applicable to the proposed project.

IV Permit Conditions

The following permit conditions will be imposed to ensure that the proposed project complies with all applicable District, State, and Federal Regulations. The conditions limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. Permit conditions will also specify abatement device operation and performance levels. To aid enforcement efforts, conditions specifying emission monitoring, source testing, and record keeping requirements are included. Furthermore, pollutant mass emission limits (in units of lb./hr) will ensure that daily and annual emission rate limitations are not exceeded.

Compliance with CO and NOx limitations will be verified by continuous in-stack emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up and shutdown. Compliance with SOx will be determined by monitoring the totaled reduced sulfur (TRS) level in the refinery fuel gas with a TRS analyzer. Compliance with POC and PM10 mass emission limits will be demonstrated by quarterly source testing.

In addition to permit conditions that apply to as designed operation of each CTG/HRSG power train, conditions will be imposed that govern equipment operation during the initial commissioning period when the CTG/HRSG power trains will operate without their SCR systems and oxidation catalysts fully operational. During this commissioning period, the gas turbines will be tested, control systems will be adjusted, and the HRSGs and auxiliary boiler steam tubes will be cleaned. Permit conditions 3 through 12 apply to this commissioning period and are intended to minimize emissions during the commissioning period and insure that those emissions will not contribute to the exceedance of any short-term applicable ambient air quality standard.

Permit Conditions

Definitions:

APCO	Air Pollution Control Officer.
MOP	Manual of Procedures.
POC	Precursor Organic Compound: Rule 1-233 excepting the non-precursor organic compound listed in Rule 1-234.
1-hour period:	Any continuous 60-minute period beginning on the hour.
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in Btu/scf.
Rolling 3-hour period:	Any three-hour period that begins on the hour and does not include start-up or shutdown periods.

Firing Hours:	Period of time during which fuel, other than pilot gas, is flowing to a unit, measured in fifteen-minute increments.
MM Btu:	million British thermal units
Start-up Mode:	The lesser of the first 256 minutes of continuous fuel flow to the Gas Turbine/HRSG after fuel flow is initiated or the period of time from Gas Turbine/HRSG fuel flow initiation until the Gas Turbine/HRSG achieves 60 consecutive minutes of CEM data points in compliance with the emission concentration limits of conditions 18(a) and 18(b) or 19(b) and 19(d).
Shutdown Mode:	The 30 minute period of time from non-compliance with any requirement listed in Conditions 18(a) and 18(b) or 19(b) and 19(d) involving termination of fuel flow to the Gas Turbine/HRSG.
Corrected Concentration:	The concentration of any pollutant (generally NOx, CO, or NH3) corrected to a standard stack gas oxygen concentration. For emission point P-60 (combined exhaust of S-1030 Gas Turbine and S-1031 HRSG duct burners) and emission point P-62 (combined exhaust of S-1032 Gas Turbine and S-1033 HRSG duct burners) the standard stack gas oxygen concentration is 15% O2 by volume on a dry basis.
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, and associated electrical delivery systems.
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager

Valero Power Plant Project – S-1030, S-1031, S-1032, S-1033
Conditions for the Approval of the Authority to Construct and Permit to Operate

1. Prior to the issuance of the Authorities to Construct for this Cogeneration project consisting of Phase I and/or Phase II, the owner will provide the following offsets: (Basis: NOx and POC)

Phase I (S-1030 and S-1031)
NOx: 13.162TPY from Certificate # 703

Phase II (S-1032 and S-1033)
NOx: 18.477 TPY Total
18.256 TPY NOx from Certificate #703
0.221 TPY POC for NOx from Certificate #682
POC: 7.401 TPY POC from Certificate #682

2. For SO2 emissions offsets, a curtailment group is established as follows: (Basis: SO2 offsets)

Curtailment Group:

Emission Sources
Total Group Baseline
S-237 Steam Boiler SG1032
S-220 Hot Oil Furnace F 4460
MTBE Ships
S-40 Boiler SG2301
Phase I
New GT/HRSG (S-1030 & S-1031)
Phase II
New GT/HRSG (S-1032 & S-1033)

a. SO2 emissions from the Curtailment Group will not exceed 34.75 TPY for any consecutive 12-month period. Shut down of a source within the group may not change this group annual limit.

b. Emissions will be calculated using fuel flow meters and the TRS Gas Chromatograph CEM's data for all sources other than MTBE ships. Emissions from MTBE ships will be calculated using the District approved method established for the ships in Application #6968, Condition #10797.

c. A quarterly report of the group emissions will be submitted to the District, in a District approved format, to document compliance.

Conditions for the Commissioning Period: S-1030, S-1031, S-1032, S-1033

3. The owner/operator of the proposed power plant (S-1030, S-1031, S-1032, S-1033) shall minimize emissions of carbon monoxide and nitrogen oxides from these sources to the maximum extent possible during the commissioning period. Conditions 3 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, the remaining conditions shall apply after the commissioning period has ended.

4. At the earliest feasible opportunity, but no later than 30 days after startup, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the Gas Turbine combustors and Heat Recovery Steam Generator duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

5. At the earliest feasible opportunity, but no later than 30 days after startup, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-60/A-62 SCR System, and A-61/A-63 CO Oxidation Catalyst System shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-1030 Gas Turbine and S-1031 Heat Recovery Steam Generator.

6. Coincident with the as designed operation of A-60/62 SCR System, the Gas Turbines (S-1030 and S-1032) and the HRSG (S-1031 and S-1033) shall comply with the NOx and CO emission limitations specified in conditions 18(a), 18(b), 19(b) and 19(d).

7. The owner/operator shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-1030 or S-1032 Gas Turbine describing the procedures to be followed during the commissioning of the gas turbine and HRSG. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NOx continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1030 or S-1032) and HRSGs (S-1031 or S-1033) without abatement by their respective SCR and CO Catalyst Systems.

8. During the commissioning period, the owner/operator shall demonstrate compliance with conditions 10 through 12 through the use of properly operated, and maintained continuous emission monitors and data recorders for the following parameters:

    - firing hours for the gas turbine and HRSG
    - fuel flow rates through the train
    - stack gas nitrogen oxide (and oxygen) emission concentrations at P-60/P-62
    - stack gas carbon monoxide emission concentrations P-60/P-62
    - stack gas SO2 emission concentrations at P-60/P-62 or fuel TRS/H2S concentrations.

    The monitored parameters shall be recorded at least once every 15 minutes (excluding calibration periods as required by the MOP or when the monitored source is not in operation) for the Gas Turbines (S-1030 and S-1032) and HRSGs (S-1031 and S-1033). The owner/operator shall use District-approved methods to calculate heat input rates, NOx mass emission rates, carbon monoxide mass emission rates, SOx mass emission rates, and emission concentrations of NOx, SOx, and CO, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

9. The District-approved continuous emission monitors specified in condition 8 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-1030 or S-1032) and Heat Recovery Steam Generator (S-1031 or S-1033). After first firing of the turbine, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO, SOx, and NOx emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

10. The total number of firing hours of S-1030/S-1032 Gas Turbines and S-1031/S-1033 Heat Recovery Steam Generators without abatement of nitrogen oxide emissions by A-60/A-62 SCR System and/or A-61/A-63 Oxidation Catalyst System shall not exceed 250 hours for each turbine and associated HRSG train during the commissioning period. Such operation of S-1030/S-1032 Gas Turbine and S-1031/S-1033 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 250 firing hours, without abatement, for each turbine train shall expire.

11. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM10, and sulfur dioxide that are emitted by the Gas Turbines (S-1030 and S-1032) and Heat Recovery Steam Generators (S-1031 and S-1033) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 22

12. Combined pollutant mass emissions from the Gas Turbine (S-1030 and S-1032) and Heat Recovery Steam Generators (S-1031 and S-1033) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines and HRSGs (S-1030, S-1031, S-1032 & S-1033).

NOx (as NO2)	360.34 pounds per calendar day
CO	513.216 pounds per calendar day
POC (as CH4)	97.776 pounds per calendar day
PM10	224.08 pounds per calendar day
SO2	516 pounds per calendar day

Conditions for the Operation of Gas Turbines (S-1030 and S-1032) and the Heat Recovery Steam Generators (HRSG; S-1031 and S-1033)

13. The Gas Turbines (S-1030 and S-1032) and HRSG Duct Burners (S-1031 and S-1033) shall be fired on refinery fuel and/or natural gas. (Basis: BACT for SO2 and PM10)

14. The combined heat input rate to the power train consisting of a Gas Turbine and its associated HRSG (S-1030 and S-1031 or S-1032 and S-1033) shall each not exceed 810 MM Btu per hour, averaged over any rolling 3-hour period. The gas turbine in each power train (S-1030 or S-1032) shall not exceed 500 MM Btu/hr. (Basis: Cumulative Increase, Permit Fees, Modification, Offsets)

15. The combined heat input rate to the power train consisting of a Gas Turbine and its associated HRSG (S-1030 and S-1031 or S-1032 and S-1033) shall each not exceed 19,440 MM Btu per calendar day. (Basis: Cumulative Increase, Permit Fees, Modification, Offsets)

16. The combined cumulative heat input rate for each power training consisting of Phase I (S-1030 and S-1031) or Phase II (S-1032 and S-1033) shall not exceed 6,351,000 MM Btu per year. (Basis: Offsets, Cumulative Increase, Modification)

17. S-1030/S-1032 Gas Turbines and S-1031/S-1033 HRSGs shall be abated by the properly operated and properly maintained A-60/A-62 Selective Catalytic Reduction (SCR) System and A-61/A-63 CO Oxidation Catalyst System whenever fuel is combusted at those sources and the catalyst bed has reached minimum operating temperature as designated by the manufacturer. (Basis: BACT for NOx)

18. The Gas Turbines (S-1030 and S-1032) and HRSGs (S-1031 and S-1033) when firing natural gas exclusively shall comply with requirements (a) through (f) under all operating scenarios, including duct burner firing mode. Requirements (a) through (f) do not apply during a start-up or shutdown mode. (Basis: BACT, PSD, and Toxic Risk Management Policy)

(a) Emissions of nitrogen oxides (NOx) at emission points P-60 or P-62 shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O_2, averaged over one hour period.(Basis: BACT for NOx when firing natural gas)

(b) The carbon monoxide emissions concentration at P-60 or P-62 shall not exceed 6 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-clock hour period. (Basis: BACT for CO when firing natural gas)

(c) Ammonia (NH_3) emission concentrations at P-60 or P-62 shall not exceed 10 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. (Basis: Toxics)

(d) Precursor organic compound (POC) mass emissions (as CH_4) from P-60 or P-62 shall not exceed 2.0372 pounds per hour or 0.002515 Lb/MM Btu of natural gas fired. Compliance will be based on the initial source test. (Basis: BACT for POC when firing natural gas)

(e) For sulfur dioxide (SO_2) emissions, the sulfur content in the natural gas shall not exceed 1.0 grain per 100 scf of natural gas. The owner shall use standard pipeline quality natural gas as supplied by PG&E. Compliance will be demonstrated in accordance with condition # 35. (Basis: BACT for SO_2 when firing natural gas),

(f) For particulate (PM10) emissions, the sulfur content in the natural gas shall not exceed 1.0 grain per 100 scf of natural gas. The owner shall use standard pipeline quality natural gas as supplied by PG&E. Compliance will be demonstrated in accordance with condition # 35. (Basis: BACT for PM10 when firing natural gas)

19. The Gas Turbines (S-1030 and S-1032) and HRSGs (S-1031 and S-1033) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode. Requirements (a) through (h) do not apply during a start-up or shutdown mode. (Basis: BACT, PSD, and Toxic Risk Management Policy)

(a) Emissions of nitrogen oxides (NOx), calculated in accordance with District approved methods as NO2, at P-60 (the combined exhaust point for the S-1030 Gas Turbine and the S-1031 HRSG after abatement by A-60 SCR System) or P-62 (the combined exhaust point for the S-1032 Gas Turbine and the S-1033 HRSG after abatement by the A-62 SCR system) shall not exceed 7.29 pounds per clock hour. (Basis: BACT for NOx, Offsets)

(b) Emissions of nitrogen oxides (NOx) at emission points P-60 or P-62 shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O2, averaged over any 3-clock hour period(Basis: BACT for NOx)

(c) Carbon monoxide mass emissions at P-60 or P-62 shall not exceed 10.692 pounds per clock hour, averaged over any rolling 3-hour period (Basis: PSD for CO)

(d) The carbon monoxide emission concentration at P-60 or P-62 shall not exceed 6 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-clock hour period. (Basis: BACT for CO)

(e) Ammonia (NH3) emission concentrations at P-60 or P-62 shall not exceed 10 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-hour period. (Basis: Toxics)

(f) Precursor organic compound (POC) mass emissions (as CH4) at P-60 or P-62 shall not exceed 2.037 pounds per hour. Demonstration of compliance will be based on source test results. (Basis: BACT)

(g) Sulfur dioxide (SO2) mass emissions at P-60 or P-62 shall not exceed 10.75 pounds per hour (rolling 24 hour average).

Sulfur concentrations in refinery fuel gas shall not exceed 35 ppm TRS (rolling consecutive 365 day average). (Basis: BACT)

Sulfur concentrations in fuel gas fired in S-1030, S-1031, S-1032 and S-1033 shall not exceed 100 ppm TRS (rolling 24 hour average). (Basis: BACT)

Hydrogen sulfide (H2S) concentrations in refinery fuel gas shall not exceed 160 ppm (rolling consecutive 3-hour average). (Basis: NSPS)

(h) Particulate matter (PM10) mass emissions from P-60 or P-62 shall not exceed 4.65 pounds per hour averaged over any consecutive 24-hours nor 1.55 pounds per hour averaged over a calendar year. This limit is subject to adjustment based on the results of source tests, in no case, however, may the adjusted limit exceed 4.65 lb/hr averaged over any consecutive 24 hours. Demonstration of compliance will be based on source test results. (Basis: BACT for PM10)

20. The sulfuric acid emissions (SAM) from P-60 and P-62 combined shall not exceed 7 tons in any consecutive four quarters. (Basis: PSD)

21. A District approved initial source test will be commenced within 60 days of startup to demonstrate compliance with the NOx, CO, POC, TRS, SO2, PM10, NH3, and SAM levels in Conditions number 18, 19 or 20. For purposes of SAM, the applicant shall also test for SO3 and ammonium sulfates. The test results shall be forwarded to the District within 60 days of completion of the field test. The test should verify emission compliance at 80% or more of maximum firing on:

1. Gas Turbine firing natural gas only
2. Gas Turbine and HRSG firing natural gas only
3. Gas Turbine firing refinery fuel gas only
4. Gas Turbine and HRSG firing refinery fuel gas only.

(Basis: Compliance Demonstration)

22. Total emissions from each power train consisting of Phase I and Phase II (S-1030, S-1031, S-1032 and S-1033) shall not exceed the following annual limits (365 day rolling average): (Basis: Cumulative Increase, Offsets, PSD)

a) Phase I (S-1030 and S-1031)

NOx - 28.603 TPY (based on CEM data)
POC – 8.579 TPY (based on Gas Turbine/HRSG POC emissions of 7.983 TPY plus fugitive emissions of 0.596 TPY)
SOx – 15.0 (based on TRS measurement)
CO - 41.9285 TPY (based on CEM data)
PM10 – 6.803 TPY (based on source test results)

Phase II (S-1032 and S-1033)

NOx - 28.603 TPY (based on CEM data)
POC – 8.332 TPY (based on Gas Turbine POC emissions of 7.983 TPY plus fugitive emissions of 0.349 TPY)
SOx – 15.0 (based on TRS measurement)
CO - 41.9285 TPY (based on CEM data)
PM10 – 6.803 TPY (based on source test results)

b) The PM10 emissions may be adjusted based on source test results for S-1030, S-1031, S-1032 and S-1033) if the particulate emission rate exceeds the assumed level. In no case shall the adjustment when added to the assumed level for Phase I exceed a total of 10.919 tons per year of PM10 emissions. This allowance is based only on the construction of Phase I. If Phase II is constructed, the adjustment when added to the assumed level in Phase I and Phase II, including PM10 emissions from the exempt wet cooling tower, shall not exceed a project total of 15.477 tons per year of PM10. The Cogeneration project increase in PM10 is limited to the available offsets for the proposed project, i.e. the contemporaneous emission reductions from the shutting down of three boilers (S-38, S-39 and S-41). The owner shall submit a new application for any increase in PM10 beyond the allowable level. (Basis: Cumulative Increase, Offsets)

c) The PM10 emissions may be adjusted based on the use of recycled water in the exempt wet cooling tower instead of fresh water. In no case shall the adjustment when added to the assumed PM10 level on fresh water exceed the total of 3.8 tons per year for the wet cooling tower (restricted to toxic risk values). This adjustment along with the allowable adjustment in Condition 22(b) shall not exceed a combined total of 10.919 tons/year in Phase I or 15.477 tons/year for both phases. The Cogeneration project increase in PM10 is limited to the available offsets for the proposed project, i.e. the contemporaneous emission reductions from the shutting down of three boilers (S-38, S-39 and S-41). The owner shall submit a new application for any increase in PM10 beyond the allowable level. (Basis: Cumulative Increase, Offsets)

d) The owner shall prepare an annual calendar-year report and submit it to the District documenting compliance with these annual limitations on mass emissions. The report shall be submitted to the District no later than 60 days after the close of the calendar year. (Basis: Compliance Monitoring)

23. To demonstrate compliance with conditions 19(f), 19(g),19(h), 20 and parts of 22, the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM10) mass emissions (including condensable particulate matter), Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO2) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM10, SAM and SO2 emissions shall be summarized for the combined power train: [Gas Turbine (S-1030)/HRSG (S-1031)] and/or [Gas Turbine (S-1032)/HRSG (S-1033)]

(b) On a daily basis, the 365 day rolling average cumulative total POC, PM10, SAM and SO2 mass emissions, for both power trains: Gas Turbine (S-1030)/HRSG (S-1031) and/or Gas Turbine (S-1032)/HRSG (S-1033).
(Basis: Offsets, PSD, Cumulative Increase)

24. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM10 emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District within 60 days of conducting the tests. (Basis: Source Test Compliance Verification)

25. The owner/operator shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, calculated compliance records, etc.) as required by District Rules or Regulations or through permit conditions, and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Basis: Regulation 2-6-502)

26. The owner/operator shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The length of time, description and quantity of excess emissions associated with breakdowns shall be included in the recordkeeping requirements. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Basis: Regulation 2-6-501)

27. The owner/operator shall notify the District of any violations of these permit conditions consistent with the requirements of the Title V permit-(Basis: Regulation 2-1-403)

28. The stack height of emission points P-60 and P-62-shall each be at least 80 feet above grade level at the stack base. (Basis: PSD, TRMP)

29. The Owner/Operator shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval. (Basis: Regulation 1-501)

30. Within 180 days of the issuance of the Authority to Construct, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Basis: Regulation 1-501)

31. The startup period for the Gas Turbines/HRSGs shall last for no more than the period defined in the Startup Mode.

32. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.3, the owner/operator of the Valero Power Plant shall submit an application to the BAAQMD for a significant revision to the Major Facility Review Permit prior to commencing operation. (Basis: Regulation 2-6-404.3)

33. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Valero Power Plant shall not operate Phase II of the cogeneration project until either: 1) a Title IV Operating Permit has been issued; 2) 24 months after a Title IV Operating Permit Application has been submitted, whichever is earlier. (Basis: Regulation 2, Rule 7)

Monitoring Requirements

34. The Cogeneration project shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Basis: Regulation 2, Rule 7)

35. The owner shall install and operate a District approved continuous refinery fuel gas fuel monitor/recorder to determine the H_2S content and total reduced sulfur content of the refinery fuel gas and natural gas prior to operation of the Cogeneration project (S-1030, S-1031, S-1032 and S-1033). This does not include pilot gas. (Basis: Refinery fuel gas and natural gas monitoring for SO2, BACT)

36. The owner shall record the rolling consecutive 3-hour average totaled reduced sulfur content and H2S content of the refinery fuel gas. On a quarterly basis, the owner shall report: (a) the daily fuel consumption, (b) hourly H2S content (as averaged over 3 consecutive hours) of the refinery fuel gas, (c) hourly total reduced sulfur content (as averaged over 24 consecutive hours), (d) quarterly daily averaged H2S content, (e) quarterly daily averaged total reduced sulfur content and (f) annual averaged reduced sulfur content using the last four quarters. The report shall be sent to the District's Director of Compliance and Enforcement, and the Manager of the Permit Evaluation Section no later than 60 days after the end of the quarter. (Basis: BACT, Offsets, Cumulative Increase)

37. The four sources (S-1030, S-1031, S-1032 and S-1033) shall be equipped with a District approved continuous fuel flow monitor and recorder in order to determine the fuel consumption. (Basis: BACT, Offsets, Cumulative Increase, Monitoring)

38. The owner shall install, calibrate, maintain and operate a District-approved continuous emission monitor and recorder for NOx, CO and O2. (Basis: Continuous Emissions Monitoring)

39. The owner shall conduct a quarterly source test to demonstrate compliance with 19 (f) for POC and 19 (h) for PM10. The owner shall conduct the tests in accordance with protocols approved in advance by the District. After acquiring one year of source test data on these units, the District may switch to annual source testing if test variability is low.
(Basis: POC and PM10 Periodic Monitoring)

40. The owner shall conduct a quarterly source test to demonstrate compliance with condition 20 for Sulfuric Acid Mist (SAM). The testing shall also include testing for SO2, SO3, SAM and ammonium sulfates. The owner shall conduct the tests in accordance with protocols approved in advance by the District. After acquiring one year of source test data on these units, the District may switch to annual source testing if test variability is low.
(Basis: PSD Avoidance, SAM Periodic Monitoring)

Fugitive Equipment

41. All hydrocarbon control valves installed as part of the Cogeneration Project in Phase I and Phase II shall be equipped with live loaded packing systems and polished stems, or equivalent. (Basis: Cumulative Increase offsets)

42. All hydrocarbon valves shall be inspected per District Regulation 8, Rule 18 using a District approved leak detection device. Any valve found to be leaking in excess of 100 ppm shall be subject to the leak repair provisions of District Regulation 8, Rule 18. (Basis: RACT)

43. All connectors installed in the piping systems as a result of Phase I or Phase II of the Cogeneration project shall be equipped with graphitic-based gaskets unless the service requirements prevent this material. Any connector found to be leaking in excess of 100 ppm shall be subject to the leak repair provisions of Regulation 8, Rule 18. (Basis: RACT, offsets, Cumulative Increase)

44. All new hydrocarbon centrifugal compressors installed as part of Phase I or Phase II of the Cogeneration project shall be equipped with “wet” dual mechanical seals with a heavy liquid barrier fluid, or dual dry gas mechanical seals buffered with inert gas. All compressors shall be inspected and repaired in accordance with District Regulation 8, Rule 18. All compressors found to leaking in excess of 500 ppm shall be subject to the leak repair provisions of Regulation 8, Rule 18. (Basis: RACT, Offsets, Cumulative Increase)

45. All new fugitive equipment in organic service will be integrated into the owner's fugitive equipment monitoring and repair program and will meet the requirements of District Regulation 8-18. (Basis: Compliance monitoring)

46. The Cogeneration project consisting of S-1030, S-1031, S-1032, S-1033 shall include the following gas fittings: no more than 600 valves, 1800 connectors and 4 compressors The annual mass limit for POC (Condition number 22) and the offsets required may be adjusted based on final fugitive component count. Any additional POC offsets required due to a larger fugitive component count will need to be provided prior to permit issuance.

<u>Contemporaneous Emissions reduction credit</u>

47. The S-38 and S-39 steam boilers shall be completely shutdown no later than 90 days after startup of the S-1030 and S-1031 power train. The applicant shall enter into the record log the date each boiler was shutdown. (Basis: offsets)

48. The S-41 steam boilers shall be completely shutdown no later than 90 days after startup of the S-1032 and S-1033 power train. The applicant shall enter into the record log the boiler was shutdown. (Basis: offsets)

V Recommendation

The APCO has concluded that the proposed Valero Cogeneration Project, which is composed of the sources in Phase I (Application number 2488) and Phase II (Application number 2695), complies with all applicable District rules and regulations. The following sources in the Cogeneration project will be subject to the permit conditions, and BACT and offset requirements discussed previously.

Phase I

S-1030 Combustion Turbine Generator: General Electric, Model LM 6000, 500 MM Btu/hr maximum rated capacity, Refinery Fuel Gas and/or Natural Gas Fired; water injected low NOx Burners; Abated by A-60 Selective Catalytic Reduction (SCR) System and A-61 CO Oxidizing Catalyst System

S-1031 Heat Recovery Steam Generator (HRSG): Duct Burner Supplemental Firing System, 310 MM Btu/hr maximum rated capacity; abated by A-60 Selective Catalytic Reduction (SCR) System and A-61 CO Oxidizing Catalyst System

Phase II

S-1032 Combustion Turbine Generator: General Electric, Model LM 6000, 500 MM Btu/hr maximum rated capacity, Refinery Fuel Gas and/or Natural Gas Fired; water injected low NOx Burners; Abated by A-62 Selective Catalytic Reduction (SCR) System and A-63 CO Oxidizing Catalyst System

S-1033 Heat Recovery Steam Generator (HRSG): Duct Burner Supplemental Firing System, 310 MM Btu/hr maximum rated capacity; abated by A-62 Selective Catalytic Reduction (SCR) System and A-63 CO Oxidizing Catalyst System

EXEMPTION

Exempt Wet Cooling Tower: 540,000 air flow rate, 5600 gpm water circulation rate for both phases (Exempt per Regulation 2-1-128.4: Water cooler tower not used for evaporative cooling of process water)

CREDITS

Phase I (S-1030 and S-1031) Without Phase II (S-1032 and S-1033) Constructed

The following credits, minus any adjustments allowed in conditions number 22(b), 22(c) and 46, will be issued to Valero upon the shutdown of the S-38 and S-39 Boiler (Condition 47):

NOx: 18.256 tons[1] (Issuance of leftover credit)

[1]Valero will surrender banking certificate #703 having NOx credits of 31.418 to satisfy this offset obligation. The remaining balance of 18.256 tons of NOx (31.418 minus 13.162) will be applied to PhaseII. If Phase II is not constructed, another banking certificate for the balance of 18.256 tons of NOx emissions will be issued back to Valero.

POC: 1.820 tons[2] (Excess Contemporaneous Emissions Reduction)

[2]Phase I will generate a POC credit of 1.820 tons/year. This credit will be applied to Phase II. If Phase II is not constructed, Valero has requested that the District issue a banking certificate for the excess POC emissions reductions credits in accordance with Regulation 2-2-606. This amount may be adjusted to account for the final fitting count.

PM10: 3.786 tons[3] (Excess Contemporaneous Emissions Reduction)

[3]Phase I will generate a PM10 credit of 4.116 tons/year. This credit will be applied to Phase II. If Phase II is not constructed, Valero has requested that the District issue a banking certificate for the excess PM10 emissions reduction credit in accordance with Regulation 2-2-606. In the event a banking certificate is issued in this situation, the District will withhold 0.33 ton/year of PM10 credits to offset the PM10 emissions from the exempt Cooling Tower as required by the CEC. Valero will be issued another banking certificate for the unused emission reduction credits [4.116 – 0.33] = 3.786 tons of PM10]. These amounts may be adjusted based upon actual PM10 emissions rates determined by compliance source tests.

Phase I (S-1030 and S-1031) and Phase II (S-1032 and S-1033) Constructed

The following credits, minus any adjustments allowed in Conditions 22(b), 22(c) and 46, will be issued to Valero upon the actual shutdown of the S-38, S-39 and S-41 boilers (Conditions 47 and 48):

POC: 7.147 tons[1] (Issuance of leftover Credits)

[1]Valero will surrender banking certificate #682 having POC credits of 14.769 tons. Valero will be issued another banking certificate for the unused emission reduction credits [14.769 – 7.401-0.221 (for NOx)] = 7.147 tons of POC]. This amount may be adjusted to account for the final fitting count.

PM10: 1.211 tons[2] (Excess Contemporaneous Emissions Reduction Credits)

[2]Phase I and Phase II combined will generate a PM10 credit of 1.871 tons of PM10 emissions. Valero has requested that the District issue a banking certificate for the excess PM10 emissions reduction credit in accordance with Regulation 2-2-606. In the event a banking certificate is issued in this situation, the District will withhold 0.66 tons/year of PM10 credits to offset the PM10 emissions from the exempt Cooling Tower as required by the CEC. Valero will be issued another banking certificate for any unused PM10 emission reduction credits. Presently, Valero is due 1.211 tons of PM10 [1.871 – 0.66] after fully offsetting the project. A certificate will be issued after the three boilers (S-38, S-39 and S-41) have been shut down. These amounts may be adjusted based upon actual PM10 emission rates determined by compliance source tests.

Ellen Garvey
Air Pollution Control Officer/Executive Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco CA 94109